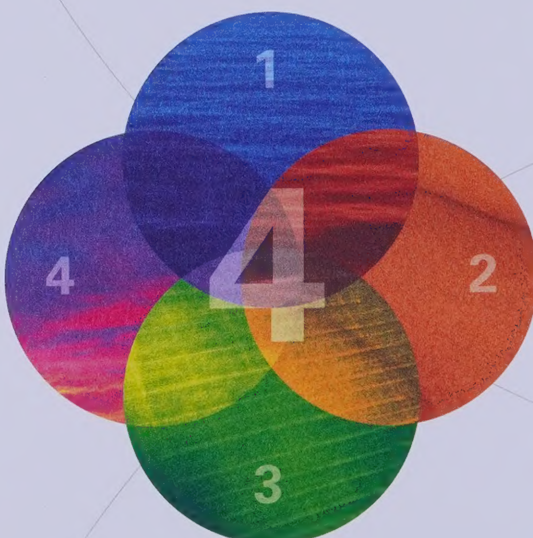
nexen

Transitioning 4 Growth

03
ANNUAL
REPORT

Transitioning 4 Growth in 4 Key Basins



1 GULF OF MEXICO
Investing in higher-margin barrels in the deep water

2 MIDDLE EAST
Growing new reserves and cash flow in low-cost areas

3 WEST AFRICA
Discovering offshore resources of significant impact

4 ATHABASCA OIL SANDS
Applying breakthrough technology to our vast resource

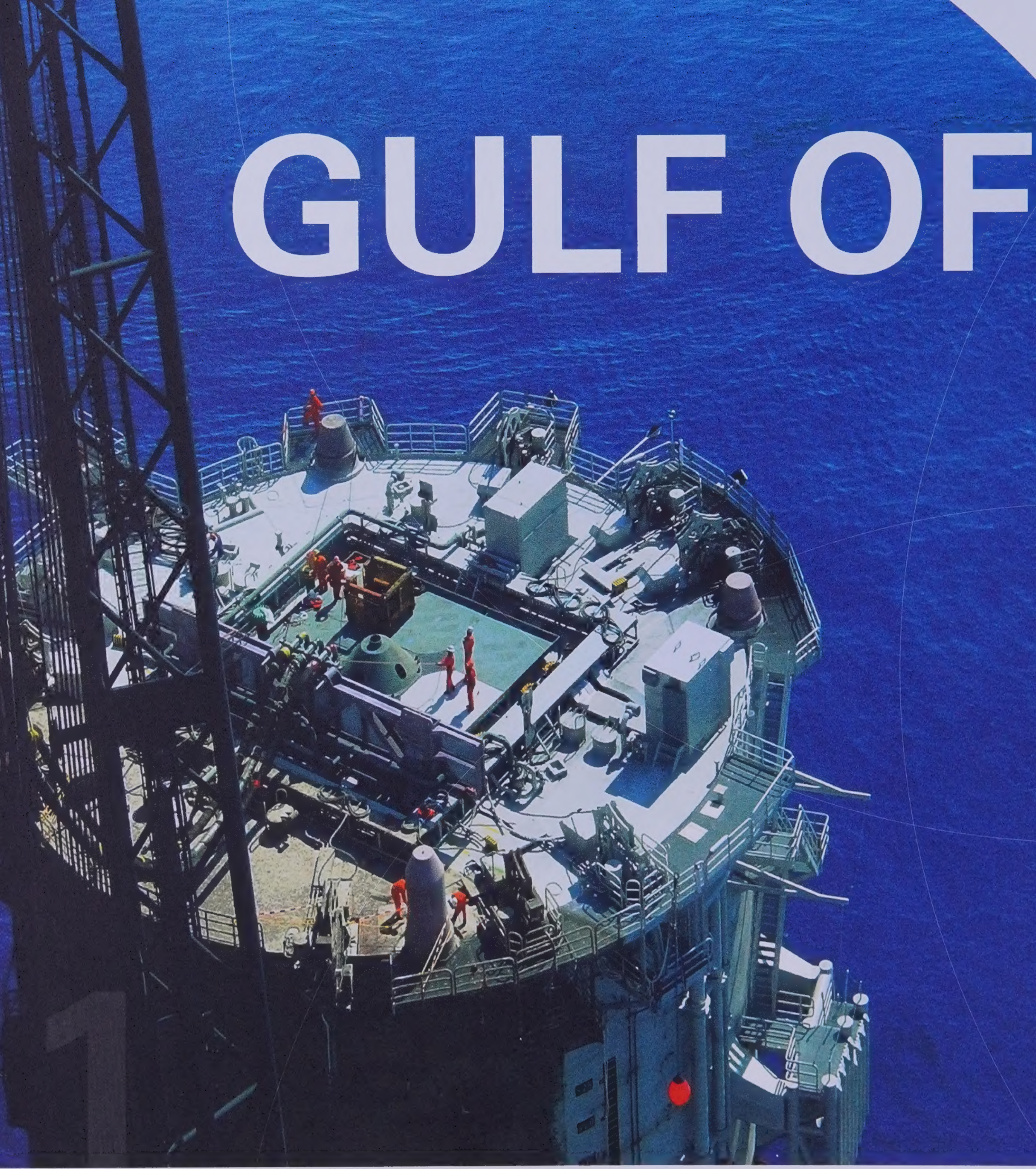
What do you see when you blend the blue waters of the Gulf of Mexico, golden sands of the Middle East, jungle green of West Africa's shoreline and the oil sands beneath Alberta's skies? A glimpse into basins where Nexen is Transitioning 4 Growth.

Nexen's Global Operations

Nexen is a Canadian-based global energy and chemicals company on a mission—to grow value responsibly. To us, value matters. It's the compelling reason for our strategic transition away from maturing conventional production in North America into 4 of the most prospective and exciting regions in the world. Better fiscal regimes, prolific basins, higher netback barrels and emerging technological solutions are just a few of the valuable elements associated with the deep-water Gulf of Mexico, the Middle East, offshore West Africa and the Canadian Athabasca oil sands.

We began planting the seeds for our transition years ago, capturing attractive opportunities not available today. We invested free cash flow from our core assets in Canada, the shallow-water Gulf of Mexico, Yemen and our chemicals business into multi-year growth projects. Today, these projects are beginning to deliver real value—visible in our record 2003 financial results. Our strategy continues as we launch new opportunities for growth, with high-quality exploration projects and subsequent phases of oil sands projects. Turn the page to see Nexen's projects in full view.

GULF OF



1988
Became a shallow-water operator

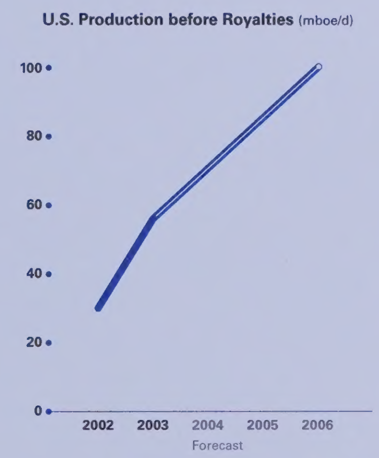
1997
Began acquiring first deep-water acreage

2000
Made first deep-water discovery

2002
Brought first deep-water productio
on stream

MEXICO

High-netback production from the deep-water Gulf is driving our corporate margins, and a line-up of high-potential drilling will propel future growth.



The Gulf of Mexico is our largest and fastest-growing business, contributing 33% of our cash flow from only 25% of total production after royalties. In 2003, in the deep water, we became an operator at Aspen and brought our second project at Gunnison (shown here) on stream. We added 21 new blocks to our enviable land position, which now totals 193 blocks in the Gulf, including 18 in the Aspen area and more than 30 surrounding Gunnison. Netbacks at Aspen and Gunnison are twice our corporate average, so cash flow grows faster than production, and we earn higher returns.

The deep-water Gulf is a great place to grow our business with large reserves, good success rates, high flow rates, excellent fiscal terms, and rapidly developing infrastructure in the world's largest oil and gas market. Plus, it's relatively immature from an exploration standpoint with plenty of opportunities for continued growth.

In 2004, we plan to invest almost one-half of our exploration capital in the Gulf to drill deep-water prospects in the Aspen and Gunnison sub-basins, the Eastern Gulf and deep gas plays on the shelf. At both Gunnison and Aspen, any discoveries can be brought on stream quickly given the existing infrastructure in these areas.

With plans to drill 5 or 6 high-impact wells every year, our goal in the Gulf is 100,000 boe per day of value-enhancing production by year-end 2006.

MIDDLE

1993
Began production at Masila, Yemen

1998
Acquired interests in 6 exploration blocks in Yemen

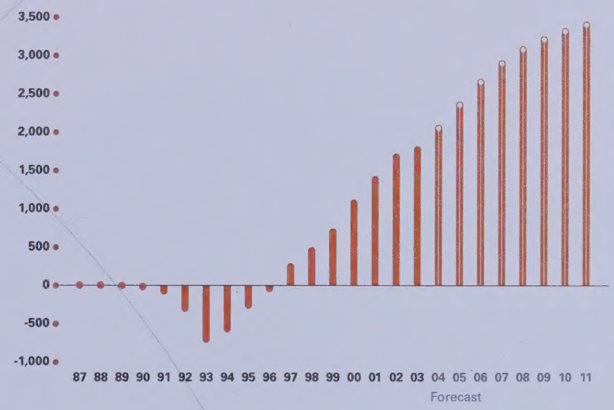
2003
Produced the 750 millionth barrel from Masila

2003
Discovered oil on Block 51 adja
to Masila

EAST

The strength of our reputation and success in Yemen positions us well for new growth opportunities and continued free cash flow from the Middle East for many years.

Cumulative Free Cash Flow from Masila (Cdn$ millions)



Yemen continues to be a core asset for Nexen. We've operated safely and without interruption for over 10 years and continue to nurture strong ties with all levels of government and local communities.

As the graph shows, we have extracted less than one-half of the project cash flow from our Masila operations. While our share of production after royalties is declining, our free cash flow will continue to grow given the cost-recovery mechanisms in our contract. With development of our Block 51 discoveries, we believe we have at least 200 million barrels still to produce in Yemen and more to come with additional exploration. So we expect to generate significant free cash flow from Yemen for several years.

On Block 51 west of Masila, our aggressive capital program at Baishir al Khair (formerly Tammum and Amir) is delivering excellent results. We are moving ahead with field development and expect between 20,000 and 25,000 barrels of daily production on stream early in 2005. We are continuing delineation drilling to assess the field's additional potential. And we plan to shoot more seismic and drill 6 exploration wells on Block 51 in 2004.

Elsewhere in the Middle East, we are seeking opportunities to capitalize on our experience, reputation and strong relationships in the region to expand our business in this low-cost basin.

WEST

1998
Started production from Ejulebe OML 109

1998
Discovered Ukot on OPL 222

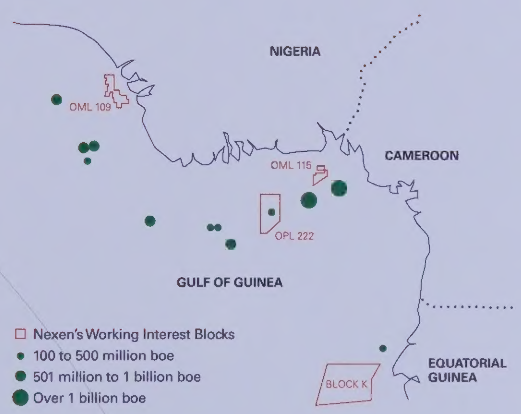
2002
Discovered Usan on OPL 222

2003
Acquired interest in OML 115 and Block K

AFRICA

As a new core area where Nexen already has discoveries, offshore West Africa offers prolific reservoirs and multiple opportunities to invest in this oil-rich basin.

Major Discoveries Since 1998



With our significant discoveries approaching commercial development and exciting new acreage, Nexen is pursuing a number of strategies to expand our presence in this attractive basin. Offshore Nigeria, appraisal of our discoveries on OPL 222 has confirmed a commercial resource. We estimate the recoverable hydrocarbon resource in the Usan field to be at least 300 million barrels (60 million, net to Nexen). The operator has applied to convert the Block's license to an Oil Mining Lease, which gives us 20 years to appraise, develop and produce the reserves. A development plan for Usan is being prepared for submission to the Nigerian government for approval. In 2004, we plan to continue exploration drilling to assess the Block's remaining potential.

Our reputation in Yemen has helped to open doors in this region for farm-in opportunities and partnerships with indigenous companies that recognize our commitment to social responsibility and the value of our technical skills. For example, in 2003, Nexen farmed into OML 115, offshore Nigeria. We also acquired an interest in Block K, offshore Equatorial Guinea. Both blocks are near significant discoveries. We plan to drill 1 or 2 exploration wells on each block in 2004. We're also well positioned to assess future acreage relinquishments and build on our growing presence in West Africa.

ATHABASCA

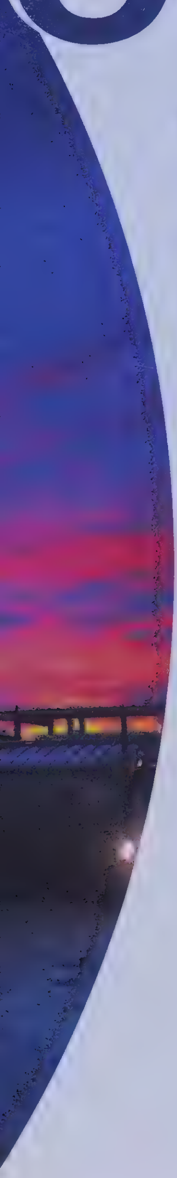
4

1978
First oil sands production from our Syncrude interest

2001
Partnered with OPTI Canada on the Long Lake Project

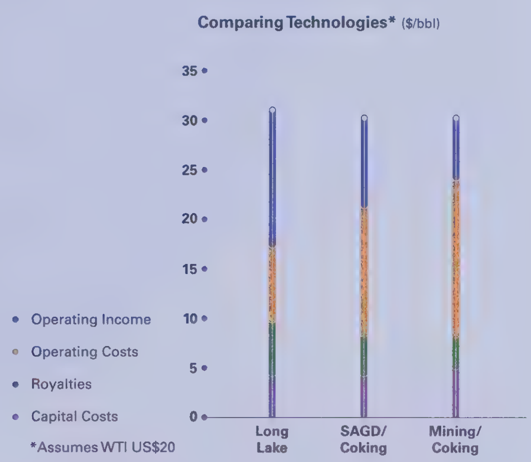
2003
Began SAGD pilot for bitumen production at Long Lake

2004
Sanctioned commercial project



OIL SANDS

New breakthrough technology married with more than two decades of experience in the oil sands provides Nexen with a substantial competitive advantage.



The Long Lake Synthetic Crude project is one of the most exciting and cost-effective oil sands developments in Canada. Our technological solution for accessing and upgrading bitumen addresses the three critical issues in this business. We will create a high-value product, more sought after by refiners than raw bitumen. We will upgrade bitumen in the field, eliminating the diluent cost normally required to transport bitumen to market. And we will generate our own fuel, so we're not buying expensive natural gas. All of this results in a cost advantage of between $4 and $7/bbl that grows as gas prices increase above US$3/mcf. Apply these savings to our more than 4 billion barrels of recoverable bitumen in the Athabasca region, and the magnitude of our advantage is readily apparent.

Our Board sanctioned this project in February 2004, and construction is scheduled to begin this fall. We've completed 20% of the design, incorporating knowledge from our SAGD pilot and upgrader demonstration plant. We're on track to start producing 60,000 bbls per day (30,000 net to Nexen) of premium synthetic crude in 2007. As Phase 1 of Long Lake taps into only 10% of our 4-billion-barrel resource, we are already planning for future phases.

Our Long Lake project will change this Company. With no exploration risk and more than 35 years of stable free cash flow from long-life reserves, it lowers Nexen's risk profile and is a great complement to our global exploration program.

LETTER TO SHAREHOLDERS

Nexen's transition for growth spans several years. We are now in the pivotal stage, investing significant capital in multi-year development projects and beginning to see the rewards in our record financial results.

2003 Record Results
Earnings up 41%, cash flow up 34%

2003 Production Growth
Up 5% after royalties

2003 Stronger Balance Sheet
Reduced net debt and preferred securities by $758 million

2003 Higher Quarterly Dividend
Increased 33% to $0.10/share in Q

	2003	2002	2001
Earnings per Share ($/share)	**4.84**	3.34	3.40
Cash Flow per Share ($/share)	**14.50**	10.71	11.20
Capital Investment ($ millions)	**1,494**	1,625	1,404
Reserve Replacement after Revisions and Dispositions (%) [1]	**40**	128	132
Annual F&D Costs after Revisions ($/boe) [1]	**29.34**	11.15	9.81
Annual F&D Costs before Revisions ($/boe) [1]	**11.64**	12.41	9.24
5-Year F&D Costs after Revisions ($/boe) [1]	**9.13**	6.86	6.24
Production before Royalties (mboe/d)	**269**	269	268
Production after Royalties (mboe/d)	**185**	176	184

1 Based on proved reserves before royalties, at year-end prices.

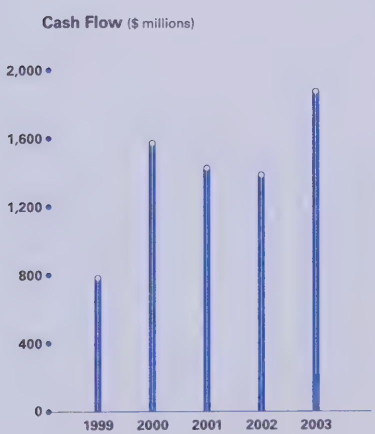
Fellow shareholders, When people ask me "What's new at Nexen," I'm proud to tell them. We're achieving record results, and we're building momentum in our 4 key basins. We're adding high-quality reserves, despite reducing our Canadian conventional reserve estimate. As you read through this letter, I think you'll agree that our strategy is working, and we're well positioned for the long term.

Employees celebrate Gunnison Spar in the Gulf

In 2003, we continued to grow our production and build our competitive position in the attractive deep-water Gulf of Mexico. We surfaced new value from our drilling activities in Yemen and offshore West Africa. And we laid the groundwork to move forward with commercial development of our industry-leading oil sands project in Canada.

We're in the midst of a transition designed to enhance value creation. Some time ago, we recognized that conventional North American basins were maturing, and we took action on two fronts. We reinvigorated our business by transitioning into under-explored areas, and we began incorporating emerging technologies in maturing regions. More specifically, we acquired significant acreage in the deep-water Gulf of Mexico in 1997 when it was most affordable. We captured opportunities offshore Nigeria in 1998 in counter-cyclical markets at prices that couldn't be replicated today. We also have a head start in the Middle East where we began building our world-class Yemen asset more than a decade ago. I am proud to report that to date, Masila has produced more than 750 million barrels. And we spent years researching various technologies for extracting the maximum value from our vast bitumen resource, before moving forward with a solution that best addresses all of the economic drivers. Now we're developing exciting growth projects, and the rewards of our efforts are beginning to show.

In 2003, our cash flow soared 34% to a record $1.9 billion, and net income topped $639 million. Much of this growth came from new, more profitable operations in the deep-water Gulf of Mexico. While 2003 production before royalties was unchanged compared with 2002, production after royalties grew 5%, and our cash flow per share climbed 10%, assuming the same prices year-over-year. This demonstrates the more valuable barrels from new projects like Aspen, where low royalties and operating costs feed our bottom line. In fact, our U.S. operations have become our largest source of cash flow and operating profit, with more growth in store now that Gunnison is on stream. Both Aspen and Gunnison are contributing high-margin barrels, with current cash netbacks almost three times their full-cycle finding and development costs. If 2003 prices prevail in 2004, we expect our 2004 cash flow to climb an additional 10%. (See my executive summary on page 27 of our 10-K for more details on our results).



2003 Gulf of Mexico	2003 Yemen	2003 West Africa	2004 Long Lake
Acquired remaining 40% interest in Aspen & brought Gunnison on stream	Block 51 discoveries added 32 mmboe proved reserves	Drilled 4 successful wells on OPL 222	Nexen's Board sanctioned the project & we booked 200 mmboe proved reserves

Our Board of Directors recently sanctioned the Long Lake Synthetic Crude Oil project, after we implemented a successful SAGD pilot project and gained regulatory approval for the commercial project in 2003. As construction begins this fall, I am confident in our project plan. Our commercial design has far more definition than other oil sands projects had when they were sanctioned. We've also learned many lessons from these projects and incorporated their actual project costs into our $3.4 billion total cost estimate. We are deploying a flexible labour strategy that enables us to attract and retain the best skilled labour to build our project. And we've integrated the advice of construction contractors into our plan. Most importantly, the project management team includes many of our own employees to ensure project scope does not creep, and we build exactly what we have designed. These are all key factors in controlling our overall costs. I am confident our employees will keep this exciting project on schedule and within budget.

Internationally, Nexen continued to be successful with the drill-bit. We are developing discoveries on Block 51 in Yemen and building facilities to add between 20,000 and 25,000 barrels per day of new oil production in the first half of 2005. Offshore Nigeria, the appraisal of our Usan discovery on OPL 222 confirmed a commercial resource base, and we are continuing to explore this attractive acreage while preparing a plan to develop these reserves.

Transitioning doesn't involve changing our strategy. It means carefully aligning our capital with opportunities that deliver long-term value to shareholders.

Throughout our operations, we minimize our reinvestment in higher-cost maturing assets, choosing instead to invest in new opportunities with long-term growth potential. That is what's driving our transition—to grow value beyond simply adding volumes. For example, in 2003, we sold higher-cost assets in southeastern Saskatchewan at attractive prices and acquired the remaining 40% interest in Aspen's low-cost, high-margin reserves. While these transactions combined had little impact on total production or reserves, every barrel added at Aspen is almost twice as valuable as the ones we sold. Now we control our destiny as a deep-water operator in the attractive Aspen basin, which contains a number of high-quality drilling prospects on our acreage.

Employees inspect SAGD pilot

In 2003, we invested only 10% of our total capital to develop Canadian conventional reserves, given the maturing state of these assets and more valuable investment opportunities elsewhere in our global operations.

Following our annual reserve evaluation, we reduced our proved reserve estimate in Canada by 60 million barrels and recorded a related charge of $175 million, net of tax, in our 2003 financial statements. Half of the revisions reflected our more conservative view of future production profiles for certain properties. The remaining reductions related to proven undeveloped reserves we no longer are certain we can recover, and changes in end-of-life economic assumptions. The revision has no impact on our 2004 production guidance, and we believe our Canadian conventional assets have significant remaining economic value. After the revision, only 10% of our reserves in Canada and 23% company-wide are proven undeveloped, as compared to a historic industry average of approximately 30%. So while I'm disappointed to see the revision, I am confident that our high level of internal and external scrutiny surrounding our reserves continues to result in top-quality reserve estimates.

Scarabeo 7 rig drills at OPL 222

The Canadian reserve revision drove F&D costs up to $29.34 per boe in 2003. Excluding the revision, our F&D costs were $11.64 per boe and have averaged $9.13 per boe over the last five years. Before revisions, we added 111 million boe of proved reserves, the majority in Yemen, the Gulf of Mexico and at Syncrude. We also added 374 million boe of probable reserves including at Long Lake and for discoveries in Yemen and offshore West Africa. These are just a portion of the reserves we expect these projects to add.

With many of our multi-year projects, we invest significant capital without immediate reserve recognition, cash flow or production. At the end of 2004, we will have deployed more than $1.5 billion in development projects that will start generating cash flow and production in 2005 and beyond. Given the long lead time of many of our projects, our growth is generally sporadic rather than following a steady and predictable climb each year. And F&D costs in any one year reflect these lumpy growth patterns. For example, with the recent sanctioning of Long Lake, we have converted 200 million barrels of probable reserves to proved reserves in 2004. These reserves alone will dramatically reduce our 2004 F&D well below 2003 levels. Had those been recorded as proved reserves in 2003, our F&D costs, before revisions, would have been an impressive $4.07 per boe. So while the timing of project sanctioning and capital programs affects our reported F&D results, it doesn't diminish the attractive economic returns we expect to deliver from these projects over their lives.

It takes discipline to stay the course we've set, especially when the market tends to reward short-term thinking. However, our projects add significant value when they come on stream and create far more value over the long term. As we bring more projects forward, the intervals between our additions will shorten. We expect Block 51 and the Syncrude expansion to come on stream in 2005, with upgraded bitumen from Long Lake in 2007 and production from OPL 222 soon after that, based on development plans still being finalized.

2004 Capital Investment	2004 Cash Flow Target	2004 Gulf of Mexico	2004 Long Lake
Invest $1.8 billion in high-quality programs	Grow price-neutral cash flow 10% above 2003	Drill 6 key wells	Begin commercial construction

Nexen's exciting exploration portfolio totals eight billion boe of resource potential, and we will be testing half a billion boe in 2004 with 17 high-impact wells.

We have a host of development and exploration wells cued-up that could add significantly to our existing projects. That's what makes our 4 key basins so attractive—there's plenty of running room for future growth with a full slate of opportunities that don't require high oil and gas prices to deliver attractive full-cycle returns. In 2004, half of our exploration capital will be invested in the Gulf of Mexico. We have excess capacity at Aspen and Gunnison, which we plan to fill with additional exploitation and exploration drilling. This year we plan to drill at least 5 exploration wells in the Gulf.

In Yemen, we continue to explore Block 51 and the deeper horizons at Masila. We're also continuing to evaluate other opportunities in the Middle East. This is a rich and prolific region where successes can be developed at low cost. Offshore West Africa, we expect to announce results for at least seven deep-water wells drilled offshore Nigeria and Equatorial Guinea this year. In all of these basins, the exploration opportunities are high quality as they offset existing discoveries or are on play types we know well. And in Canada, we've sketched out a long-term, multi-phased plan for our synthetic crude project to access more of our 4 billion-barrel resource. With over 35 years of annuity-type cash flow stream and attractive returns on capital, Long Lake provides a solid base for renewed growth in Canada.

Masila operations in Yemen

Our core assets and solid financing strategy are key to our transition. Our traditional assets in Canada, the U.S. Shelf, Masila and our chemicals and marketing operations continue to provide the free cash flow to finance our major development projects. This year, only one-third of our $1.8 billion capital program will be reinvested in these assets to sustain near-term production. The Buffalo field, offshore Australia, and Ejulebe, offshore Nigeria, will be fully depleted in 2004. This, combined with our 2003 Canadian asset disposition, means our production before royalties will be flat or down marginally in 2004. However, production after royalties will continue to grow.

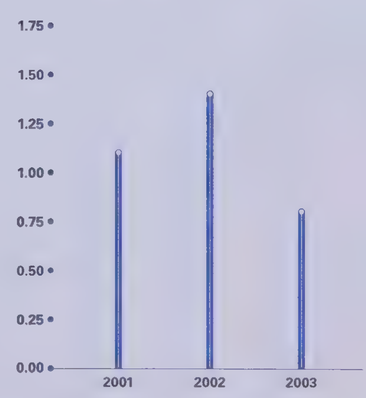
In Canada, we're using new technology to extract maximum value from the conventional basin in new projects like coal bed methane (CBM), enhanced oil recovery and of course, the oil sands. We are pleased with the encouraging results from our CBM pilot project at Corbett and expect to establish commerciality in 2004, giving new legs to otherwise maturing conventional assets.

Our marketing group continues to provide a key source of market intelligence that helps us make sound investment decisions. The team had their best year ever in 2003, generating strong contributions to cash flow and earnings. They are focused on providing superior customer service and finding success in low-risk trading strategies that capitalize on price differences between the various markets we serve. In our chemicals business, we continue to focus on cost-reduction initiatives including relocating sodium chlorate capacity to Brandon, Manitoba, from Taft, Louisiana. When this project is completed, our Brandon plant will be the world's largest sodium chlorate facility and will have the lowest cost structure in North America. Internationally, in our chemicals operations, we continue to solidify our presence in Brazil and are well positioned to capture growth opportunities throughout South America.

Our financing strategy ensures funding for our multi-year capital programs despite potential volatility in our cash flow as prices fluctuate.

In 2003, we reduced our net debt and preferred securities by $758 million. This was aided by excess cash flow from high commodity prices and improving margins, and also by asset sales and a strong Canadian dollar. We have redeemed both issues of preferred securities and refinanced US$225 million of senior debt, taking advantage of low interest rates. Today, our net debt is less than one year of cash flow. Its average term to maturity is over 20 years, and most of our debt is publicly held. With more than $0.5 billion in cash and $1.6 billion of undrawn lines of credit, we are well positioned to fund our major capital requirements. Our balance sheet is in great shape as we look ahead to significant development programs over the next few years.

Net Debt to Cash Flow* (times)



*After dividends on preferred securities

Etched in stone throughout this transition is our commitment to corporate governance and social responsibility. I see this as one of our strongest competitive advantages. We are proactively meeting or exceeding all rules mandated by securities regulators and Sarbanes-Oxley. Operating with integrity and transparency has enabled us to be successful in some of the world's most challenging regions. This fall, we celebrated 10 years of uninterrupted operations in Yemen, an outstanding accomplishment for us and for the people of Yemen. In Canada, we've worked hand-in-hand with communities surrounding our Balzac gas plant to ensure safety and environmental performance is paramount. At Long Lake, we shared our development plans with local communities and groups affected by these

2004 Yemen
Develop Block 51 discoveries

2004 West Africa
Drill 7 exploration wells

2004 Canada
Decide on CBM commerciality

2004 Board of Directors
Appoint Eric Newell to the Board

plans, and proactively addressed their concerns—a testament to our thorough practices in environmental and community consultation.

Yemeni girls greet Nexen at 10th anniversary

In today's world, success requires that we address more than purely economic benefits. It requires careful consideration of social, cultural, human rights, environmental, health and safety issues. In 2003, we saw dramatic declines in our employee injury incident rate—which was already amongst the lowest in our industry—and we continue working towards our goal of zero incidents. Our values are opening opportunities in emerging areas as partners recognize our commitment to social responsibility and government relations. Clearly our way of doing business creates value for shareholders.

I am proud of our accomplishments and consider Nexen fortunate to have exceptional employees who turn our strategic ideas into reality.

Throughout Nexen, we continue to foster a culture that promotes innovation and knowledge sharing so we all work towards a common goal—increasing long-term shareholder value in an ethical and socially responsible way. Our employees have responded by saying they enjoy working here. Once again, they selected us as one of the 50 best companies to work for in Canada.

We continue to appreciate the strategic guidance our independent Board of Directors provides. I also welcome Eric Newell to our Board. He brings years of oil sands expertise that is extremely valuable as we embark on commercial development of Long Lake.

Charlie visits field operations

As we move forward through our transition, there are a few things I know for certain. We continue to think and act strategically to position ourselves for significant growth in what I consider the world's best basins. We are equipped with all the right tools—great assets, skilled people and a proven strategy for success—all propelling our Company to new levels of performance. Nexen will continue to be profitable and successful, delivering the long-term value growth that our shareholders have come to expect.

I look forward to our ongoing communications and to sharing our strategic progress with you throughout the year, including at our AGM on May 4. Thank you for continuing to support Nexen.

CHARLIE FISCHER, PRESIDENT AND CEO

February 20, 2004

1997 Leadership
International Code of Ethics for Canadian Business

2001-2003 Top 50 Companies to Work For
Ranked by employees in The Globe and Mail's *Report on Business*

2002 Employee Award
United Way Leadership Giving Award

VALUES MATTER

COMPETITIVE ADVANTAGE: INTEGRITY

At Nexen, values matter. Our company culture fosters responsible and ethical choices, an environment where every employee's action is a transparent window on Nexen's integrity.

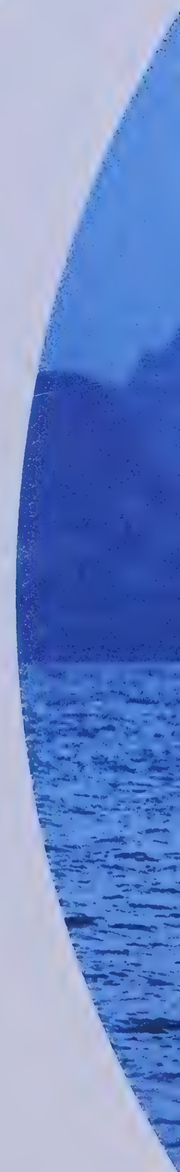
Our values are visible throughout Nexen. Our Board of Directors sets the direction for good corporate governance and is attentive to any new and emerging issues. Management provides leadership, and our employees integrate their values into actions everyday.

Our actions clearly reflect the values we hold. In 1997, we championed the development of the International Code of Ethics for Canadian Business. Our new Integrity Evergreening program takes integrity for employees a step further to ensure our value system stays vital. In late 2003, we embarked on an external audit of our internal management system for safety, environment and social responsibility.

Our reputation for operating with integrity results in advantages for shareholders. It helps to attract and retain excellent employees, lowering our turnover rate. It enables us to attract partners, bringing superior opportunities. It earns us goodwill in local communities, resulting in improved security and uninterrupted production. And it enables us to secure the capital we need, accelerating our opportunities for value-added growth.

2003 Ethics Award	2003 United Way Giving	2003 Champions Award	2003 Leadership
Better Business Bureau of Southern Alberta	Nexen and our employees donate more than $1 million	Recognition from The Canadian Paraplegic Association	Charlie Fischer named Calgary's Individual Philanthropist of the Year

INTEGRATING OUR VALUES: SUSTAINABILITY



On land and water, Nexen's successful and sustainable approach to social and environmental responsibility benefits the communities we affect, and ultimately, our shareholders.

Nexen's goal is to build successful, sustainable partnerships in communities where we operate. Ultimately, we want to be a neighbour of choice. Our approach is working. For example, our extensive community consultations helped ensure a smooth regulatory approval for our Long Lake project. By involving stakeholders in our plans, we are earning their trust and support.

Nexen operates under the same strict environmental and safety standards worldwide. Our number of reportable environmental incidents continues to decline, and in 2003 we achieved our best performance ever. We also believe in taking action on environmental stewardship. As part of our involvement in the United Nations Global Compact initiative, Nexen is one of the first companies to partner with the UN in developing a $1.5 million, three-year water and sanitation project in Yemen.

For shareholders, our transparent and sustainable approach lowers risk, as people trust our ethical policies, internal controls and disclosure. Our approach makes us welcome in communities and grants us a "social licence to operate".

1997-2003 Ongoing Yemen Scholarships
60 scholarships for post-secondary study in Canada

2001-2003 Dow Jones Sustainability Index
1 of only 3 Canadian-based oil & gas companies

2002 World First for Oil & Gas Facility
Balzac Gas Plant Responsible Care® Verification

2003 *Corporate Knights Magazine*
Nexen ranked 4th best corporate citizen in Canada

We have a big story to tell. Our 10-K and Performance Review are filled with details on our operations, management's discussion of our results, our financial statements and our corporate governance practices. Let us help you navigate.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) of THE SECURITIES EXCHANGE ACT OF 1934

For the year ended December 31, 2003

Commission File Number 1-6702

NEXEN INC.

Incorporated under the Laws of Canada

98-6000202
(I.R.S. Employer Identification No.)

801 – 7th Avenue S.W.
Calgary, Alberta, Canada T2P 3P7
Telephone - (403) 699-4000
Web site - www.nexeninc.com

Securities registered pursuant to Section 12(b) of the Act:

Title	Exchange Registered On
Common shares, no par value	The New York Stock Exchange The Toronto Stock Exchange
Subordinated Securities, due 2043	The New York Stock Exchange The Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days. Yes √ No ____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes √ No ____

On June 30, 2003, the aggregate market value of the voting shares held by non-affiliates of the registrant was approximately Cdn $4.2 billion based on the Toronto Stock Exchange closing price on that date. On January 31, 2004, there were 126,738,410 common shares issued and outstanding.

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Special Note to Canadian Investors - see page 60

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided in tabular format.

Below is a list of terms specific to the oil and gas industry. They are used throughout the Form 10-K.

/d	=	per day	mboe	=	thousand barrels of oil equivalent
bbl	=	barrel	mmboe	=	million barrels of oil equivalent
mbbls	=	thousand barrels	mcf	=	thousand cubic feet
mmbbls	=	million barrels	mmcf	=	million cubic feet
mmbtu	=	million British thermal units	bcf	=	billion cubic feet
km	=	kilometre	WTI	=	West Texas Intermediate
			NGL	=	natural gas liquid

Oil equivalents are used to convert quantities of natural gas with crude oil by expressing them in a common unit. To calculate equivalents, we use 1 bbl = 6 mcf of natural gas.

The noon-day Canadian to US dollar exchange rates for Cdn $1.00, as reported by the Bank of Canada, were:

(US$)	December 31	Average	High	Low
1999	0.6929	0.6730	0.6929	0.6537
2000	0.6666	0.6733	0.6973	0.6413
2001	0.6279	0.6458	0.6695	0.6241
2002	0.6331	0.6369	0.6618	0.6199
2003	0.7738	0.7135	0.7738	0.6350

On January 31, 2004, the noon-day exchange rate was US$0.7539 for Cdn $1.00.

Electronic copies of our filings with the Securities Exchange Commission (SEC) and the Ontario Securities Commission (OSC) (from November 8, 2002 onward) are available, free of charge, on our website (www.nexeninc.com). Filings prior to November 8, 2002 are available free of charge, upon request, by contacting our investor relations department at (403) 699-5931. As soon as reasonably practicable, our filings are made available on our website once they are electronically filed with the SEC or the OSC. Alternatively, the SEC and the OSC each maintain a website (www.sec.gov and www.sedar.com) that contain our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the OSC.

PART I

Items 1 and 2. Business and Properties

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BACKGROUND

Nexen Inc. (Nexen, we or our) is a Canadian-based global energy and chemicals company incorporated under the laws of Canada.

We are one of the largest independent Canadian oil and gas exploration and production companies. We explore for, develop and produce conventional crude oil and natural gas primarily in western Canada, the United States (US) Gulf of Mexico, the Middle East and offshore West Africa. We develop and produce synthetic crude oil in Canada's Athabasca oil sands region.

We also manage a growing crude oil and natural gas marketing business and manufacture, market and distribute sodium chlorate, caustic soda and chlorine in North and South America.

Our history is set out below:

Date	Event
July 12, 1971	We were formed under the name Canadian Occidental Petroleum Ltd. (COPL) through a reorganization by Occidental Petroleum Corporation (Occidental) of Los Angeles, California, which combined the crude oil, natural gas and sulphur operations of its 55% owned subsidiary, Jefferson Lake Petrochemicals of Canada Ltd., and the operations, including chemicals, of its wholly owned subsidiary, New Hooker Canada Ltd.
May 20, 1983	We purchased Canada-Cities Service, Ltd. (Cities Service) for $354 million. The acquisition doubled our size, while substantially increasing reserves and revenues partly through a 13.23% interest in the Syncrude Project. COPL and Cities Service amalgamated and continued under the name COPL on January 1, 1984.
February, 1984	We acquired Cities Offshore Production Co., a company that held interests in producing oil and gas fields in the Gulf of Mexico, offshore Louisiana, for US$132.5 million.
May 31, 1988	We purchased Moore McCormack Energy, Inc. a company with mostly onshore operations in Texas, Louisiana and Alabama.
	During 1988 we sold 6% of the interest we acquired in Syncrude through the Cities Service acquisition for approximately $330 million. We retained a 7.23% interest.
April 14, 1997	We acquired Wascana Energy Inc. (Wascana) as a result of a take-over bid. The total purchase price for Wascana was approximately $1.7 billion. Wascana became a wholly-owned subsidiary as a result of an amalgamation on June 30, 1997.
April 17, 2000	We entered into an agreement with Ontario Teachers' Pension Plan Board (Teachers) and Occidental where Occidental sold its 29% interest in COPL, which was approved by a majority of shareholders other than Occidental or Teachers. Teachers purchased 20.2 million common shares, we repurchased the remaining 20 million common shares for $605 million ($29.61 per share) including associated fees, and exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemicals operations.
November 2, 2000	Further to the sale of Occidental's interest we changed our name to Nexen Inc.

STRATEGY

Our goal is to grow long-term shareholder value by generating an attractive return on every dollar of capital we invest. In the oil and gas industry, creating value means long-term growth per share in reserves, production, cash flow and earnings, independent of price volatility.

We pursue a grassroots, exploration-led strategy supplemented by strategic acquisitions and the development of innovative technology. Our value-based strategy is supported by:

- solid core assets that provide free cash flow to finance our new growth development projects;
- active exploration programs aimed at adding to our portfolio of new growth projects; and
- a culture based on integrity and social responsibility.

We believe this strategy of full-cycle exploration and development can deliver the best overall returns. To succeed, we continue to locate and develop economic oil and natural gas reserves. We allocate capital to projects based first on their investment returns and strategic fit, and second on the potential to grow reserves and production. In building our portfolio, we target material opportunities that balance risk and reward, have multiple opportunities for continued growth and build on our technical skills. Our goal is to operate most of our core assets and control offsetting acreage and infrastructure for future development.

Recognizing some time ago that conventional North American basins were maturing, we began transitioning to under-explored areas, and incorporating emerging technologies in maturing regions. We positioned ourselves in four of the world's most attractive areas for oil and gas exploration and development:

- the deep-water Gulf of Mexico;
- the Middle East;
- offshore West Africa; and
- the Canadian Athabasca oil sands.

These areas offer an optimal combination of prospectivity, attractive commercial terms and low costs. Given our exploration success over the past several years, we are now executing multi-year development projects in each area that are starting to add significant value to Nexen.

We maximize value in our marketing operations by providing superior customer service and growing our business with low-risk opportunities. Our marketing group provides a key source of market intelligence that helps us make sound investment decisions. For chemicals, our strategy is to remain a low-cost producer in North America, while capturing an increasing share of the growing markets in South America.

OPERATIONS

Nexen has operations in four main areas:

- Conventional Oil and Gas
- Athabasca Oil Sands
- Oil and Gas Marketing
- Chemicals

For financial reporting purposes, these areas are defined as reportable segments. Conventional oil and gas is further broken down into geographic segments. Information on production, revenues, net income, capital expenditures and identifiable assets for these segments for the past three years appears in Note 15 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

Conventional Oil and Gas

We explore for, develop and produce conventional crude oil, natural gas and related products around the world. Our core assets are located in the United States (US) Gulf of Mexico, Yemen and western Canada, with other producing properties offshore Australia and Nigeria, and onshore in Colombia. We continue to develop new growth opportunities in the Middle East and offshore West Africa.

We generally manage our operations on a country-by-country basis reflecting differences in the regulatory environments and risk factors associated with each country. The oil and gas industry is highly competitive and this is particularly true when searching for, and developing, new sources of supply, and in constructing and operating crude oil and natural gas pipelines and facilities.

Crude oil and natural gas commodities are sensitive to numerous worldwide factors and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices can significantly affect our net income and cash generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and our level of spending for oil and gas exploration and development.

We have a broad customer base for our crude oil and natural gas. Alternative customers are generally available, therefore, the loss of any one customer is not expected to have a significant adverse effect. Oil and gas operations are generally not seasonal, except for heavy oil which generally experiences higher demand in the summer months.

United States – Gulf of Mexico

■Nexen Producing Blocks ■Nexen Exploration Blocks
● Major Producing Fields
□AMI with Shell Exploration and Production Company

Acreage (thousand acres)	Developed	Undeveloped	Total
Shallow-Water			
Gross	168	152	320
Net	94	99	193
Deep-Water			
Gross	23	734	757
Net	11	337	348
Total			
Gross	191	886	1,077
Net	105	436	541

Proved Reserves	Before Royalties	After Royalties
Crude Oil (mmbbls)	75	67
Natural Gas (bcf)	304	256
Total (mmboe)	126	110

2003 Production	Before Royalties	After Royalties
Shallow-Water		
Crude Oil (mbbls/d)	7.8	6.5
Natural Gas (mmcf/d)	124	103
Total (mboe/d)	28.5	23.7
Deep-Water		
Crude Oil (mbbls/d)	20.5	18.5
Natural Gas (mmcf/d)	21	19
Total (mboe/d)	24.0	21.7
Total (mboe/d)	52.5	45.4

Our oil and gas assets offshore in the US Gulf of Mexico are our single largest source of cash flow. We currently hold interests ranging from 3.7% to 100% in 193 federal lease blocks in the Gulf, 133 of which are located in water depths exceeding 1,000 feet.

Our strategy in the Gulf is to explore for new deep-water reserves and for new deep gas trends on the shelf, acquire assets with upside, and exploit our existing asset base.

Royalties on our oil and gas production in the US average approximately 15% of working interest volumes. Aspen and Gunnison qualify for royalty relief on the first 87.5 million equivalent barrels. The Gunnison leases are also subject to price threshold limitations which could require annual royalty payments. Royalties on other Gulf and state water properties range from 12.5% to 25%. Profits from our US operations are subject to the US federal tax rate of 35%. State taxes in the jurisdictions in which we operate range from 0% to 8%.

Shallow-water Exploration and Production

Our shelf production comes from our assets located offshore Louisiana and Texas, primarily in four fields: Eugene Island 18, Eugene Island 255/257/258/259, Eugene Island 295, and Vermilion 76 (consisting of blocks 65, 66 and 67). We continue to exploit these assets, and look for other opportunities on the shelf.

In late 2001, we acquired 100% working interests at Vermilion 76 and Eugene Island 295. Since then we have drilled 12 development wells at Vermilion 76, meeting our growth expectations and more than doubling field production to approximately 40 million cubic feet per day. In the first quarter of 2003, we restored production at Eugene Island 295. The field was shut-in during the second half of 2002 from extensive damage caused by Hurricane Lili. Daily field production at year-end was approximately 22 million cubic feet of natural gas.

In 2002, we signed an agreement with Shell Exploration and Production Company (Shell) to jointly explore a 1,044 square-mile area in the south Timbalier and Ship Shoal areas on the shelf. We have a 40% interest in this exploration area. We are targeting natural gas in deep shelf reservoirs. This play is attractive because it has deep-water type reserve potential but is located within the shelf infrastructure. We drilled a dry hole in 2002 in this play. We have recently finished drilling the Shark exploration well, located on south Timbalier 174, to a depth of 25,743 feet. This is the deepest well drilled to date in the shelf. No commercial hydrocarbons were encountered and the well is temporarily abandoned while we evaluate the data collected from the well bore. We expect to drill two additional deep shelf wells in 2004 in the Main Pass area.

Deep-water Exploration and Production

Over the past decade, the deep-water Gulf of Mexico has moved from an exploration frontier to one of the most prospective sources of oil and gas production in the world. The deep-water Gulf is generally characterized by multiple productive horizons and high production rates, which greatly reduces risk and improves economics. The technology to find, drill, and develop deep-water discoveries is rapidly progressing and becoming more cost effective. In addition, the deep-water Gulf is in close proximity to infrastructure and continental US markets, allowing oil and gas discoveries to be quickly brought on stream. Large discoveries, high success rates, production infrastructure and attractive fiscal terms make this a premier exploration opportunity.

In 1997, we began building a deep-water acreage position, and shifted our exploration focus from the shelf into the deep water, where we are one of the largest independent leaseholders. In 2000 and 2001, we had discoveries in the Gunnison and Aspen sub-basins. Appraisal drilling justified proceeding with the commercial development of both sub-basins.

In 2003, we drilled Santa Rosa and Shiloh, exploratory wells located in the eastern Gulf of Mexico in deep water. Both wells were written off. Shiloh encountered hydrocarbons but in non-commercial quantities. The results were promising, we acquired additional acreage in the area and exploration activity is ongoing.

ASPEN

Aspen is located on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the Shell-operated Bullwinkle platform 16 miles away. Production commenced in December 2002. In March 2003, we acquired the remaining 40% interest in Aspen and five exploration blocks in the area for US$113 million. This acquisition established Nexen as a deep-water operator and increased our exploration acreage in the greater Aspen area to over 80,000 net acres. Aspen is producing 22,000 boe per day, of which 15% is natural gas. Returns from Aspen are attractive with cash netbacks twice our corporate average.

We are currently drilling our third development well at Aspen. We plan to follow up Aspen Well No. 3 with an exploratory well at Crested Butte, located on the next block west of Aspen at Green Canyon Block 242.

GUNNISON

In 2001, our Board of Directors approved plans to develop our 30% interest in the Gunnison sub-basin. This area is located approximately 170 miles offshore Louisiana in water depths just over 3,100 feet, and includes Garden Banks Blocks 667, 668 and 669. One discovery was located in May 2000 on Garden Banks Block 668 and a second discovery was located June 2001 on Garden Banks Block 667.

Gunnison began producing in December 2003 with the tie-in of three subsea wells. Our share of production from the field at year-end was approximately 39 mmcf of gas and 1,200 bbls of oil per day.

Gunnison produces from a truss SPAR platform with a design capacity of 40,000 barrels of oil per day and 200 million cubic feet of gas per day. A total of ten wells will be tied-in to the SPAR. Production will continue to grow throughout most of 2004 as the remaining seven wells are completed and brought on-stream. Peak daily rates of 28,000 to 30,000 bbls of oil and 165,000 to 180,000 mcf of gas are expected at the end of 2004. This would fill approximately 75% of the capacity of the facility, leaving room for growth from exploration and the processing of third-party volumes. The Dawson Deep exploration well on Garden Banks Block 625 was drilled to a total depth of 24,450 feet. The well encountered hydrocarbons and is currently sidetracking to delineate the extent of the reservoirs. Dawson Deep is located in 2,900 feet of water, northeast of our existing Gunnison facility.

OTHER

In 2003, we entered into an agreement with Shell to jointly explore a 1,116 square mile area of the deep-water eastern Gulf of Mexico. The area of mutual interest consists of 124 blocks located in Mississippi and Desoto Canyon. Shiloh was the first exploratory well to be drilled under the agreement. This well was drilled to a total depth of over 24,000 feet and was abandoned.

We are continuing to explore in the deep-water Gulf and to increase our land position. In 2003, we acquired an additional 21 blocks. In 2004, we plan to drill at least three high-potential exploration wells.

Middle East

Yemen

Acreage (thousand acres)	Developed	Undeveloped	Total
Gross	44	19,547	19,591
Net	23	9,798	9,821

Proved Reserves (mmbbls)	Before Royalties	After Royalties
Masila Block	161	91
Block 51	31	19
	192	110

2003 Production (mbbls/d)	Before Royalties	After Royalties
Masila Block	116.8	57.5

Our strategy in Yemen is to:

- maintain production rates and fully exploit the Masila Project;
- develop new growth on Block 51; and
- continue to explore on the Masila Block.

Masila Block

We have a 52% working interest in and operate the Masila Project. The Masila Project is the largest single source of oil production in Yemen and has grown steadily since discovery in 1990. To date, the 16 fields on the block have produced 750 million gross barrels of oil from total gross recoverable reserves of just over one billion barrels. We have the right to produce oil from the Masila fields until 2011 and the right to negotiate a five-year extension.

The Production Sharing Agreement (PSA) governing the Masila Project was signed with the Yemen Government in March 1987 with the first exploratory well drilled at Sunah where oil was discovered in 1990. Additional discoveries quickly followed at Heijah and Camaal. Commerciality was declared in December 1991 with the development plan approved by the Government in May 1992. Initial production began in July 1993 with the first lifting of oil in August 1993. Masila blend oil is sweet and averages 31° API at very low gas oil ratios.

Facilities consist of over 600 km of flowlines from the individual wells, which connect to larger gathering lines for transport of crude oil, water and gas to the central processing facility. From there, the crude oil is transported by pipeline over 138 km of rugged terrain to the export terminal located near Ash Shihr on the Gulf of Aden.

The export terminal consists of one 1,000,000 barrel and five 500,000 barrel storage tanks from which oil is pumped to an offshore loading buoy located in 150 feet of water for loading onto tankers.

Gross production was maintained throughout the year at approximately 224,500 barrels per day, net of fuel use of approximately 4,700 barrels per day. Currently the majority of crude oil production comes from the Upper Qishn formation. Oil is also produced from formations below the Upper Qishn including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand, and Basement formations.

Production from the Masila Project is governed by a PSA between the Government of Yemen and the Masila joint venture partners including Nexen (Partners). Under the terms of the agreement, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the Project's exploration, development, and operating costs which are funded by the Partners. Costs are recovered from a maximum of 40% of production each fiscal year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for 4 years
Development	16.7% per year for 6 years

The remaining production is profit oil that is shared between the Partners and the Government on a sliding scale based on production rates. The Partners' profit oil share ranges from 20% to 33%. The Government's share includes a provision for Yemen income taxes payable by the Partners at a rate of 35%. In 2003, the Partners' share of production from the Masila Project, including recovery of past costs, was approximately 37%.

The economics of Masila production are attractive. Over the past two years, finding and development costs have averaged approximately US$6 per barrel and operating costs have averaged US$1.40 per barrel, resulting in excellent returns for shareholders. In addition, the structure of the agreement moderates the impact on the Partners' cash flows during periods of low prices. We recover our costs first, and then share any remaining profit oil with the Government. At current production levels, the Government is entitled to approximately 73-74% of the profit oil. If price goes down, we still recover the same amount of costs, but the profit oil is decreased.

Yemen crude oil is sold based on reference prices, generally Dated Brent crude oil (Brent), adjusted for transportation and quality. West Texas Intermediate (WTI) normally trades at a premium to Brent, but the differential can vary during the year. As the demand for Brent crude oil increases relative to WTI the differential narrows, increasing the price of Brent on a relative basis. During 2003, we sold our Masila crude oil for an average discount of US$3.29/bbl to WTI.

Block 51

Block 51 is governed by a PSA between the Government of Yemen, and the partners comprising The Yemen Company (TYCO) (an entity owned by the Government of Yemen) and Nexen. The PSA expires in 2023 and we have the right to negotiate a five-year extension.

Our most exciting drilling results to date come from exploration wells drilled in 2003 at Baishir al Khair BAK-A (formerly Tammum) and BAK-B (formerly Amir). Late in 2003, we declared commerciality on this block with approval from the Yemen Government. On declaration of commerciality, 36% of the remaining block was converted to a development area for a period of 20 years. The remainder of the block was relinquished. The additional potential of the block will continue to be evaluated in 2004.

Based on drilling results to date, we expect to develop at BAK-A in excess of 60 million barrels of reserves and add between 20,000 and 25,000 barrels per day of production capacity in early 2005. Development of the BAK-A discovery will commence in 2004. Initial development will include ten additional wells, a central processing facility, a gathering system and a 22 km tieback to our Masila export pipeline.

Under the terms of the PSA, a royalty ranging from 3% to 10% is payable to the Government, after which the remaining production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the project's exploration, development and operating costs, which are funded solely by Nexen. Costs are recovered from a maximum of 50% of production each fiscal year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	75% per year, declining balance
Development	75% per year, declining balance

The remaining production is profit oil that is shared between the partners and the Government on a sliding scale based on production rates. The partners' profit oil share ranges from 20% to 30%, of which we are entitled to 87.5%. The remaining 12.5% of the partner share is payable to TYCO. The Government's share of profit oil includes provision for Yemen income taxes payable by the partners at a rate of 35%.

In 2003, we also drilled a third prospect (HEK) 25 km northwest of BAK-B, however, the well was dry. We also completed a 2D seismic program and have begun processing the data. We will continue exploring the block and plan to drill at least six exploration wells in 2004.

Exploration Blocks

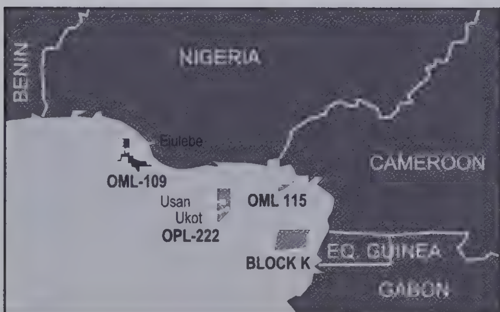
BLOCK 50

We successfully farmed out a portion of this block in 2002. Following completion of the 2003 exploration program by the new partner, our interest was reduced to 33.337%. All commitments have been fulfilled and we plan to relinquish this block in 2004.

NORTHERN BLOCKS

The Northern Blocks comprise five large exploration blocks (11, 12, 36, 54 and 59) that cover almost 13 million acres. They are located 250 km north of Masila in an undeveloped frontier area bordering Saudi Arabia. We currently have a 60% working interest in these blocks. We have evaluated these blocks and intend to relinquish them in 2004.

WEST AFRICA



Acreage (thousand acres)	Developed	Undeveloped	Total
Gross	1	1,630	1,631
Net	1	404	405

Proved Reserves (mmbbls)	Before Royalties	After Royalties
Ejulebe Field	-	-

2003 Production (mbbls/d)	Before Royalties	After Royalties
Ejulebe Field	2.2	1.6

Offshore West Africa, we have three projects underway, OPL-222 and OML-115, offshore Nigeria and Block K, offshore Equatorial Guinea. We also produce crude oil offshore Nigeria at Ejulebe on Block OML-109. Our strategy is to explore and quickly develop our current portfolio. Our 2004 program for Nigeria includes five exploration wells with the potential to deliver significant medium-term growth.

Nigeria

Block OML-109 - Ejulebe

We operate the Ejulebe field located in 45 feet of water on Block OML-109 in the Niger Delta, approximately 15 km offshore Nigeria. Crude oil production from Ejulebe is transported through a pipeline to a third-party owned FPSO (floating production storage and off-loading vessel) where it is made available for export. We operate the block under a risk service contract, which requires us to provide exploration, development and operatorship services and fund all costs in return for a service fee payable out of production from the block.

We expect the Ejulebe field to produce its final barrel of crude oil in early 2004. Abandonment will commence upon receipt of government approval. Since government approval for field decommissioning in Nigeria is in the early stages of development, official approval may take some time. No capital expenditures are proposed for 2004.

Block OPL-222

In 1998, we acquired a 20% interest in Block OPL-222, which includes 448,000 acres and is located approximately 80 km offshore in water depths ranging from 600 to 3,500 feet. Elf Petroleum Nigeria Limited, a subsidiary of Total, is the operator. The ongoing appraisal of the block indicates significant hydrocarbon accumulations based on the drilling results outlined below:

- In 1998, the Ukot-1 exploration well encountered three oil-bearing intervals and flowed at a restricted rate of 13,900 bbls per day from two intervals.
- In 2002, the Usan-1 exploration well encountered several oil-bearing intervals and one zone flowed at a restricted rate of 5,000 bbls per day.
- In 2003, the Usan-2 well was drilled three km west of the discovery well, Usan-1, and appraised an up-dip portion of the fault block.
- In 2003, Usan-3 was drilled approximately two km northwest of the discovery well and appraised a separate fault block. One zone in the well was production tested and produced 5,600 bbls of oil per day under restricted flow conditions.

- In 2003, Ukot-2 was drilled 3.5 km south of Ukot-1 and was not flow tested.
- In 2003, the Usan-4 appraisal well flow tested two zones. They flowed at restricted rates of 4,400 and 6,300 bbls of oil per day.

Usan-4 confirmed the presence of commercial quantities of crude oil. The operator has applied to convert the block's licence to an Oil Mining Lease which gives 20 years to appraise, develop and produce the reserves. A field development plan is being prepared for submission to the government.

Priority to date has focused on the Usan field. We plan additional exploration drilling on OPL-222 in 2004. The partners are currently in the process of determining which prospects will be drilled.

Block OML-115

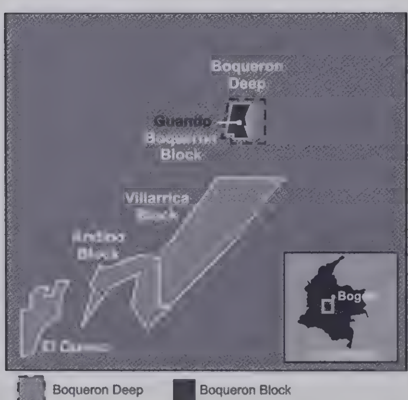
The Nigerian Government formally approved the Deed of Assignment for Block 115 in December 2003, which assigned us a 40% interest in the block. Under the terms of our Joint Operating Agreement with Oriental Energy Resources Limited, we have a 100% paying interest and are entitled to 90 - 95% of the revenues for an initial ten-year period. Existing 3D seismic is currently being evaluated to finalize our first exploration well location. In January 2004, we commenced a 410 km^2 3D seismic program on the block. Additional prospects identified by this program will be pursued in 2005.

Equatorial Guinea

In 2003, we acquired a 25% interest and became the operator of Block K, a deep-water block located 100 km offshore Equatorial Guinea. We expect to interpret existing 3D seismic and drill two exploration wells in 2004. This program will meet all work commitments under the production sharing contract prior to the end of the initial exploration period on June 1, 2005.

Other International

Colombia



Acreage (thousand acres)	Developed	Undeveloped	Total
Gross	1	909	910
Net	-	674	674

Proved Reserves (mmbbls)	Before Royalties	After Royalties
Guando	10	10

2003 Production (mbbls/d)	Before Royalties	After Royalties
Guando	3.2	3.0

Boqueron Block – Guando

In 2000, we made our first discovery at Guando on the non-operated Boqueron Block. Boqueron is located in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Based on successful results from four appraisal wells and three development wells, we submitted an application for commerciality early in 2002. Our application was accepted by Ecopetrol, the national oil company. Ecopetrol exercised their right to back into a 50% interest in the development, reducing our interest from 40% to 20%. Under the arrangement, we have recovered our share of costs incurred on Ecopetrol's behalf before they exercised their back-in right, from production.

Development drilling and a waterflood pilot program began in 2002 and continued in 2003. Given the results from the pilot, a full-field waterflood program was approved in 2003. With a full-field waterflood and 24 planned development wells, we expect our share of production will grow to 4,900 bbls per day by the end of 2004.

Production from Guando is subject to a 5% to 25% royalty depending on daily production levels. The corporate income tax rate is 38.5%.

Exploration Blocks

Exploration activities in Colombia are focused on assessing potential drilling opportunities on captured blocks. In addition to Boqueron, we have interests in four exploration blocks in the Upper Magdalena Basin. Villarrica was acquired in 2000, Andino in 2002, El Queso in 2003 and Boqueron Deep in 2003.

Block	Interest (%)	2003 Activity
Boqueron Deep	40	Signed the block in 2003
Villarrica	50	Interpreted seismic and submitted environmental impact assessment
El Descanso	50	Relinquished the block
Andino	100	Drilled Andino-1 exploration well and evaluated 50 km of seismic
Muisca	100	Relinquished the block
El Queso	100	Signed the block in 2003 and evaluated 71 km of seismic

The fiscal policy structure in Colombia is being revised to make the terms competitive in the world market. The revised terms are to be finalized in early 2004 and the El Queso block will have the option to use the new terms. Boqueron Deep has favourable terms, whereby Ecopetrol retains the right to back-in at the declaration of commerciality for a 30% interest. The exploration commitments have been completed for the current phase on all blocks except for Boqueron Deep. A decision to renew or relinquish the blocks will be made by mid-2004.

At Andino, an exploration well was drilled in October 2003, which tested wet and was abandoned. A 50 km 2D seismic program was also completed in 2003. The El Queso Block, which we acquired in 2003, is highly prospective with eight leads identified. We have completed a 71 km seismic program and will be evaluating the data to determine our future plans on this block.

Australia

Acreage (thousand acres)	Developed	Undeveloped	Total
Gross	1	-	1
Net	1	-	1

Proved Reserves (mmbbls)	Before Royalties	After Royalties
Buffalo Field	1	1

2003 Production (mbbls/d)	Before Royalties	After Royalties
Buffalo Field	6.1	5.6

Buffalo

The Buffalo field located offshore on the northwest shelf of Australia has been an excellent project. This field produces high-quality crude oil that attracts a premium price. Production from Buffalo began in December 1999 using a fixed wellhead platform linked to a leased floating production storage and off-loading vessel (FPSO). In late 2000, we acquired the remaining 50% interest in this field and became the operator.

As a result of an extensive 3D seismic reprocessing program in 2001, we identified additional oil reserves that would not be recovered by the existing production wells. In 2002, we successfully completed a two well infill drilling program which allowed us to maximize our reserve recovery and to add incremental recoverable reserves.

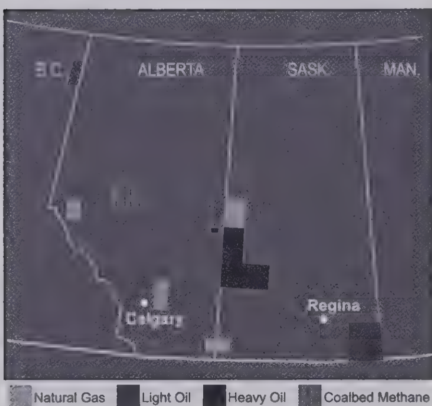
We expect to produce our final barrel of crude oil in late 2004. The final date of production will be determined by the economics of the field as we continue to maximize the remaining value through cost-effective operations. No capital expenditures are expected in 2004. Field abandonment is scheduled to begin in the fourth quarter of 2004 and finish by the end of 2005.

In Australia, profits from offshore production, less allowable capital expenditures, are subject to Petroleum Resource Rent Tax (PRRT) at a rate of 40%. Any PRRT paid is deductible in computing corporate income tax. The corporate income tax rate in Australia is 30%.

Brazil

In 2002, we acquired the right to earn a 20% interest in a 2,060 sq. km exploration license in Block BC-20 located in the Campos Basin, approximately 100 km offshore Brazil, by way of a farm-in arrangement. The first well in a two-well drilling commitment was drilled in late 2002 and the second in 2003. We encountered no economic hydrocarbons. This farm-in provided us with a strategic entry into Brazil and has enabled us to build on our offshore knowledge in an under-explored basin. We continue to evaluate our opportunities in this basin.

Western Canada



Acreage (thousand acres)	Developed	Undeveloped	Total
Gross	902	2,511	3,413
Net	705	1,417	2,122

Proved Reserves	Before Royalties	After Royalties
Crude Oil and NGLs (mmbbls)	119	101
Natural Gas (bcf)	470	405
Total (mmboe)	197	169

2003 Production	Before Royalties	After Royalties
Light Oil (mbbls/d)	20.1	15.0
Heavy Oil (mbbls/d)	26.2	20.4
Natural Gas (mmcf/d)	158	125
Total (mboe/d)	72.6	56.2

Our strategy in western Canada is to maximize value from our core operations while we actively pursue emerging sources of supply in the western Canadian sedimentary basin. These operations provide steady cash flow and earnings from our established portfolio of light oil, heavy oil, and natural gas assets. Additionally, we are advancing three promising initiatives for future growth in western Canada: gas exploration, coal bed methane development and enhanced recovery technology. Our exploration program targets high productivity deep gas plays in the foothills of Alberta where we have production operations. We have a coal bed methane extraction pilot in central Alberta, and we are actively testing enhanced oil recovery techniques on our heavy oil fields.

Light Oil

We continue to focus on the development and full exploitation of our Hay property in northeast British Columbia. We discovered Hay in 1997 and brought production on stream in April 2000. It is now the largest producing oil field in British Columbia. In 2003, we produced our eight millionth barrel from the field and drilled 23 wells to increase productivity at low cost. In 2004, we will add 17 producing development wells to further exploit the existing pool and drill five vertical wells to test the pool boundaries.

We also produce light oil in southeast Saskatchewan. Our operations in the area are characterized by mature fields producing medium depth, Mississippian age light oil. In 2003, we drilled 19 development wells on our light oil properties. We also sold land holdings in the area during the year producing approximately 9,000 bbls of oil per day (7,000 bbls, net to us) for approximately $30,000 per daily flowing barrel, realizing $268 million of net proceeds from the transaction.

Heavy Oil

There are a significant number of large heavy oil fields in western Canada. Typically, finding and development costs for heavy oil are lower than light oil. Heavy oil is characterized by high specific gravity or weight, and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult to extract, transport and refine than other types of oil.

Heavy oil yields a lower price relative to light oil, because a smaller percentage of high value petroleum products can be refined from a barrel of heavy oil than from a barrel of higher quality crude without expensive refinery conversion capacity.

Our heavy oil operations are located in west central Saskatchewan. A strong focus on managing finding and operating costs is fundamental to maximizing heavy oil returns. Our large production base and existing infrastructure are important factors in managing these costs. In 2003, a total of 54 heavy oil wells were drilled and brought on production. A key success for heavy oil will be the development of new technology to increase oil recovery.

ENHANCED OIL RECOVERY

Heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs providing the opportunity for increased recovery with the application of new technology. We are currently researching the use of solvent mixtures of hydrocarbon gases to enhance our heavy oil recovery. Early field test results at our Plover Lake field are encouraging.

Natural Gas

Our natural gas is primarily produced from shallow sweet assets in Alberta and Saskatchewan, and from deep sour gas near Calgary and in the foothills of Alberta.

Approximately 48% of our natural gas production comes from shallow low permeability gas properties. Shallow gas is natural gas produced from thin, shallow sand formations predominantly located in southern areas of Alberta and Saskatchewan. These reservoirs typically cover a broad geographical area yielding sweet, low-pressure gas. In general, shallower gas targets are cheaper to drill and develop, but have relatively smaller reserves and lower productivity per well. We also have sweet gas operations from shallow high permeability sands in northwest Saskatchewan. This is a mature area comprising 26% of our natural gas production. Our shallow gas properties provide production and consistent returns as they approach full development, and will continue to do so for years to come. During 2003, we drilled 78 shallow gas development wells.

Our Balzac field produces 13% of our natural gas and we process it through our Balzac plant, northeast of Calgary. The Balzac area has been in operation since 1961 and is characterized by long life reserves and consistent cash flows. During the year, we drilled three development wells on our Balzac property.

The balance of our natural gas production comes from the Findley properties in the Alberta foothills and gas production associated with oil wells.

Future growth in natural gas will come from gas exploration prospects in the foothills of Alberta and Montana, and from the development of coal bed methane.

GAS EXPLORATION

In 2004, our gas exploration will concentrate on the foothills of west central Alberta. In northeast British Columbia we are working to farmout out our prospective acreage. At Lochend, located just outside Calgary, public consultation for the drilling of a deep exploratory well will continue in 2004.

Our core foothills area is anchored by the producing Findley field where we actively drilled for new reserves in 2003. We drilled five wells in the year, the best of which flowed 8.5 mmcf/d (gross). Development drilling will continue into 2004 along with facility expansion to handle the extra volume. In this trend we have been able to assemble a good undeveloped land base and we plan to drill three exploratory wells in 2004 to test multiple targets.

COAL BED METHANE

Coal bed methane (CBM) is becoming a significant gas resource in Canada. CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through absorption to the coal itself rather than in the pore space of the rock, like most conventional gas. The gas is released in response to a drop in pressure in the coal. If the coal is water saturated, water will need to be extracted to initially reduce the pressure and allow gas production to occur. If the coal is gas saturated, little or no water will be produced, and gas will be produced from the onset of production. Typical water saturated CBM wells show increasing gas production rates for a period of generally one to three years before rates begin to decline. Although CBM production comprises approximately 8% of the total domestic gas production in the United States, Canadian CBM production is estimated to be only producing approximately 20 to 25 mmcf/d, or less than 0.2% of current gas production. The National Energy Board forecasts that CBM production in Canada could be as much as 3 bcf/d by 2025.

Our CBM project at Corbett is still in the pilot phase and results are largely meeting our expectations. We are partnered on this project with an experienced US CBM operator. In 2003, we added 114 sections at 100% working interest of prospective lands along the Corbett trend, increasing our total CBM land position in this area to over 240 net sections. We are currently expanding our pilot operation at Corbett from 15 to 49 producing wells. We plan to decide on commerciality by the end of 2004. Outside of Corbett, we have established a foothold in four other prospective CBM areas.

Royalties and Taxes
In Canada, the federal and provincial governments impose royalties on oil and gas production from lands where they own the mineral rights. Royalties vary depending on factors such as well production volumes, selling prices, recovery methods, drilling date of the well, and the date of initial production. Royalty rates can range from 16% to 25%.

Some provinces also receive revenue by imposing taxes on production from lands where they do not own the mineral rights. In addition, the Province of Saskatchewan assesses a resource surcharge of 3.6% on gross Saskatchewan resource sales. This surcharge has been reduced to 2.0% on wells completed after October 1, 2002.

Profits earned in Canada from Canadian resource properties are subject to federal and provincial income taxes. In 2003, legislation was introduced to reduce the general federal corporate income tax rate on income from Canadian oil and gas activities from 28% to 21% over a five-year period (2003-2007). The federal capital tax rate is 0.225%. This tax is to be repealed by 2008 through a combination of rate reductions and an increased exemption. Provincial capital tax rates vary from 0.15% to 0.60%. Canadian entities are also subject to capital taxes.

Athabasca Oil Sands

A key part of Nexen's strategy is the economic development of our bitumen resource to provide low risk, stable future growth. World events in the last three years have highlighted the need to develop stable oil resources in various areas of the world. The bitumen resource in northern Alberta has a significant role to play in providing this stability.

The US Geological Survey now recognizes bitumen as reserves. It is estimated that there are over 300 billion barrels of recoverable bitumen in northern Alberta. 20% of this resource is recoverable by way of surface mining. The remaining 80% is too deep for surfacing mining recovery and requires Steam Assisted Gravity Drainage (SAGD) technology.

We have a 7.23% joint venture interest in Syncrude Canada Ltd. (Syncrude). Syncrude mines shallow deposits of oil sands in Canada, extracts the bitumen and upgrades it to produce synthetic crude oil. We also have interests in numerous oil sands leases in the Athabasca region of northern Alberta and have acquired the rights to proprietary, patent-protected technology to upgrade bitumen recovered from these leases. We are in the development stage of our synthetic crude oil project at Long Lake.

Syncrude

Acreage (thousand acres)	Developed	Undeveloped	Total
Gross	117	141	258
Net	9	10	19

Proved Reserves (mmbbls)	Before Royalties	After Royalties
	285	248

2003 Production (mbbls/d)	Before Royalties	After Royalties
	15.3	15.2

Syncrude was created in 1975 to mine shallow deposits of oil sands and extract and upgrade crude oil bitumen into a high-quality, light, synthetic crude oil. The oil sands are located on eight leases (10, 12, 17, 22, 29, 30, 31, 34) spanning 258,000 acres north of Fort McMurray, Alberta. Since start-up in 1978, Syncrude has produced nearly 1.5 billion barrels of synthetic crude oil. The operating term for leases controlled by Syncrude currently extends to the year 2035. However, Syncrude can hold the leases for 80 years if there are plans to develop them.

Syncrude mines oil sands at three mines: Base, North and Aurora. Approximately two tons of oil sands are required to produce one barrel of synthetic crude oil. The oil sands must be mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Base Mine involves hot water, steam and caustic soda to create a slurry, while at the North Mine and the Aurora Mine the oilsands are mixed with warm water to produce a slurry.

The slurries are transported to extraction facilities where they are treated to remove water and solids. The bitumen product is fed into a vacuum distillation tower and two cokers for primary upgrading. The resulting products are then separated into naphtha, light gas oil and heavy gas oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities and are mixed together to form light, sweet synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The quality of Syncrude's synthetic crude oil typically allows it to be sold at a premium to WTI.

Expansion

In 1999, the Alberta Energy and Utilities Board (AEUB) approved an increase in Syncrude's production capacity to 465,700 barrels per day. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 barrels per day (17,820 barrels net) with the development of the Aurora Mine. In 2001, the Syncrude owners approved the third stage of the Syncrude expansion, which will increase capacity to 356,000 barrels per day (25,750 barrels net) in 2005. Due to higher engineering, manufacturing, and construction costs, the estimated costs of the Stage 3 expansion have increased from initial estimates of $4.1 billion ($296 million net) to $5.7 billion ($412 million net). Activities in 2004 will focus on completing the upgrader expansion and replacing bitumen production capacity that will be lost with the mined-out southwest quadrant of the Mildred Lake Base Mine in 2005.

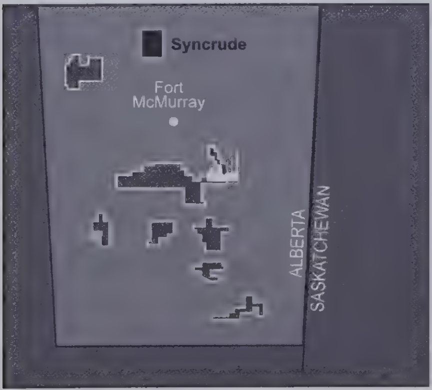
Royalties

Syncrude pays a royalty to the Province of Alberta. Subsequent to 1987, this royalty was equal to 50% of Syncrude's deemed net profits after deduction of certain capital expenditures. In 1995, the Province announced generic royalty terms for new oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. In 1997, the Province of Alberta and the Syncrude owners agreed to move to the generic royalty terms when the total of all allowed capital costs incurred after December 31, 1995 equaled $2.8 billion (gross). That total was surpassed at the end of 2001, and so Syncrude moved to generic terms in January 2002.

Long Lake Synthetic Crude

We have interests in numerous oil sands leases in the Athabasca region of northern Alberta – one of the largest non-conventional oil deposits in the world. These bitumen resources can be produced using Steam Assisted Gravity Drainage (SAGD), a technology now being commercialized at several locations in the region. SAGD involves the drilling of two parallel horizontal wells, generally between 2,300 and 3,300 feet in length with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. Recovery factors of 50% to 70% of the oil-in-place are possible with this technology. We have interests in SAGD projects at various stages of development including a 50% interest in a joint venture with OPTI Canada Inc. (OPTI).

OPTI Joint Venture



Proposed Long Lake Upgrader
Nexen Bitumen Acreage
Exclusive OPTI Technology Rights

In 2001, we formed a joint venture with OPTI to develop in-situ bitumen using SAGD technology, and to construct a field upgrading facility on the Long Lake property, incorporating patented OrCrude™ technology licensed to OPTI. As part of the agreement, Nexen acquired the exclusive right with OPTI to use the technology within approximately 100 miles of the Long Lake property, and the right to use the technology elsewhere in the world.

The OrCrude™ technology converts bitumen into partially upgraded sour crude oil and liquid asphaltenes. A 500-barrel per day demonstration plant applying this technology has been successfully upgrading bitumen from the Cold Lake and Athabasca regions since April 2001. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, the sour crude will be upgraded to light (37° to 43° API) premium synthetic crude oil and the asphaltenes will be converted to a low-energy, synthetic fuel gas containing free hydrogen (for use in the upgrading process). We estimate the capital costs of producing and upgrading bitumen using this technology will be comparable to those of surface mining and coking upgrading on a barrel of daily production basis. In addition, the project will have significantly lower price risk on input costs, since it manufactures its hydrogen and fuel gas from internally produced asphaltenes rather than purchased natural gas.

An application to construct a 70,000 barrel per day SAGD project and an integrated 70,000 barrel per day input (60,000 barrel per day premium synthetic crude output) upgrader at Long Lake (Lease 27) was granted regulatory approval in 2003. We are the operator of the Long Lake lease and are responsible for construction, development and operation of the SAGD project, while OPTI is responsible for the design, construction and operation of the upgrader.

The Long Lake SAGD and upgrader project will develop approximately 10% of our Athabasca bitumen resource and will upgrade the bitumen into a high quality, light, sweet synthetic crude oil. To optimize the project's well design, a three-well pair SAGD pilot capable of producing 3,000 barrels per day of bitumen was completed and commissioned. Wells were transitioned from the warm-up phase to SAGD production to reach 1,500 bbls per day (gross) by year-end as we expected.

On February 12, 2004, our Board of Directors approved proceeding with commercial development of the Long Lake SAGD and upgrader project and as a result we have booked 200 million barrels of new proved reserves in 2004. Field construction work is expected to begin in 2004. Commercial production of bitumen is expected in the second half of 2006 with synthetic crude oil production expected in 2007. Peak production will reach 60,000 bbls per day (gross) of synthetic crude oil and is expected to be maintained over the project's 35 plus year life. We expect the gross capital cost to construct the Long Lake project to total $3.4 billion ($1.7 billion, net to us). Ongoing sustaining capital is expected to average $2.50 per barrel. The project will generate its own fuel and electricity, resulting in significant operating cost savings when compared to other bitumen production and upgrading projects. Operating costs are expected to average $7 - $9 per barrel. Assuming WTI oil prices average in the US$ mid-twenties per barrel, the project will generate returns in the low to mid-teens.

Reserves, Production and Related Information

In addition to the tables below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Net Sales by Product from Continuing Operations

(Cdn$ millions)	2003	2002	2001
Conventional Crude Oil and Natural Gas Liquids	1,654	1,539	1,328
Synthetic Crude Oil	240	245	225
Natural Gas	618	345	494
	2,512	2,129	2,047

Crude oil and natural gas liquids represent approximately 75% of oil and gas sales, while natural gas represents the remaining 25%.

Sales Prices and Production Costs

(Based on working interest production after royalties)

	Average Sales Price [1]			Average Production Costs [1]		
	2003	2002	2001	2003	2002	2001
Crude Oil and NGLs (Cdn$/bbl)						
Yemen	39.45	38.80	35.05	4.37	4.13	3.47
Canada [2]	32.37	31.13	24.86	10.00	8.98	7.90
United States	37.68	38.88	38.35	5.08	10.95	7.24
Australia	43.14	40.30	38.71	20.21	12.14	14.38
Other Countries	38.22	38.96	37.35	9.01	10.69	9.94
Synthetic Crude Oil	43.36	40.89	39.90	22.18	18.21	20.29
Corporate Average	38.04	37.13	33.10	8.43	8.72	7.65
Natural Gas (Cdn$/mcf)						
Canada [2]	5.64	3.57	5.02	0.65	0.70	0.54
United States	8.16	5.29	6.66	0.89	1.83	1.21
Corporate Average	6.85	4.25	5.69	0.75	1.10	0.81

Notes:
1 Prices and unit production costs are calculated using our working interest production after royalties.
2 Includes results of discontinued operations. (See Note 9 of our Consolidated Financial Statements).

Producing Oil and Gas Wells

(number of wells)	2003					
	Oil		Gas		Total	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
United States	192	86	200	120	392	206
Yemen	332	173	-	-	332	173
Nigeria	2	2	-	-	2	2
Canada	2,672	1,928	2,484	2,174	5,156	4,102
Colombia	51	11	-	-	51	11
Australia	3	3	-	-	3	3
Total	3,252	2,203	2,684	2,294	5,936	4,497

Notes:
[1] Gross wells are the total number of wells in which an interest is owned.
[2] Net wells are the sum of fractional interests owned in gross wells.

Oil and Gas Acreage

(thousands of acres)	2003					
	Developed		Undeveloped [1]		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	191	105	886	436	1,077	541
Yemen [2]	44	23	19,547	9,798	19,591	9,821
Nigeria [2, 3, 4]	1	1	524	128	525	129
Equatorial Guinea	-	-	1,106	276	1,106	276
Canada	902	705	2,511	1,417	3,413	2,122
Colombia [5]	1	-	909	674	910	674
Brazil	-	-	509	102	509	102
Australia	1	1	-	-	1	1
Conventional Total	1,140	835	25,992	12,831	27,132	13,666
Syncrude	117	9	141	10	258	19

Notes:
[1] Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.
[2] The acreage is covered by production sharing contracts.
[3] The acreage is covered by a risk service contract.
[4] The acreage is covered by a joint venture agreement.
[5] The acreage is covered by an association contract.

Drilling Activity

(number of net wells)

2003	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
United States	-	0.5	0.5	8.3	0.1	8.4	8.9
Yemen	8.0	1.0	9.0	49.0	-	49.0	58.0
Nigeria	0.6	-	0.6	-	-	-	0.6
Canada	15.4	1.7	17.1	157.7	2.5	160.2	177.3
Colombia	-	1.0	1.0	6.2	-	6.2	7.2
Brazil	-	0.2	0.2	-	-	-	0.2
Total	24.0	4.4	28.4	221.2	2.6	223.8	252.2

2002	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
United States	-	1.4	1.4	14.9	0.6	15.5	16.9
Yemen	-	0.6	0.6	38.0	1.0	39.0	39.6
Canada	16.0	4.0	20.0	225.0	8.0	233.0	253.0
Australia	-	-	-	2.0	-	2.0	2.0
Other Countries [1]	0.2	0.7	0.9	2.0	0.2	2.2	3.1
Total	16.2	6.7	22.9	281.9	9.8	291.7	314.6

2001	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
United States	3.8	1.2	5.0	5.3	-	5.3	10.3
Yemen	-	1.5	1.5	30.7	1.6	32.3	33.8
Canada	38.6	20.8	59.4	369.9	8.3	378.2	437.6
Australia	-	0.4	0.4	-	-	-	0.4
Other Countries [1]	1.2	2.9	4.1	1.8	0.4	2.2	6.3
Total	43.6	26.8	70.4	407.7	10.3	418.0	488.4

Note:
[1] Other countries include drilling primarily in Nigeria, Colombia and Brazil.

Wells in Progress

At December 31, 2003, we were in the process of drilling three wells (1.6 net) in the United States, nine wells (7.3 net) in Canada, and five wells in Yemen (3.0 net).

Oil and Gas Marketing

Our marketing operation sells our own crude oil and natural gas production, markets third-party crude oil and natural gas and engages in energy trading through the use of both physical and financial contracts (energy trading activities). These activities are intended to enhance price realizations from selling both proprietary and third-party oil and gas production, provide market and business intelligence in support of our oil and gas growth activities, and contribute independent earnings and cashflow.

We focus on four key areas: domestic oil marketing and trading, domestic gas marketing and trading, international oil marketing and trading, and power marketing. We have offices in Calgary, Houston, Denver, Detroit, and Singapore to service our primary markets.

The oil and gas areas are involved in the purchase, transport, storage and sale of oil or natural gas from the point of production to end-use customers. Related to this, our marketing operation owns transportation assets and has investments in third-party controlled gas-processing facilities. Transportation assets include pipelines and batteries in the Lloydminster area as well as the Hay pipeline. In addition, we manage various natural gas transportation and storage commitments for ourselves as well as third-party clients. These management arrangements help optimize our energy trading activities. We also trade on active markets such as the New York Mercantile Exchange and the International Petroleum Exchange as part of our total portfolio.

Power marketing is involved in power production and marketing power to larger commercial, industrial and municipal clients within Alberta. It is responsible for optimizing the use of Nexen's power generation facility at Balzac, Alberta. This facility began operations during the fourth quarter of 2001.

Chemicals Operations

Our global strategy is to add value by enhancing our cost position, maintaining our market share, building a strong sustainable customer base in North America and by capturing new opportunities offshore. Over the past four years, we have made significant investments to grow our capacity, expand internationally and lower our overall cost structure. These investments have allowed us to maintain a strong position in the bleaching chemicals industry. We manufacture sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil for distribution in those countries and the US. We also market a small amount of sodium chlorate in Asia.

Average Annual Production Capacity	2003	2002	2001
Sodium Chlorate (short-tons)			
North America	432,812	500,650	474,250
Brazil	70,213	57,320	42,550
Total	503,025	557,970	516,800
Chlor-alkali (short-tons)			
North America	356,002	351,844	351,844
Brazil	109,430	97,462	90,078
Total	465,432	449,306	441,922

The key factors for marketing bleaching chemicals are reliability of supply and price. Our manufacturing facilities are modern, reliable, and strategically located to capitalize on competitive power costs or transportation infrastructure in order to minimize production and delivery costs. Electricity is the single largest cost incurred by our operations, representing over half of our cash costs. Other primary raw materials used in the production of sodium chlorate and chlor-alkali products are salt and fresh water. We secure long-term contracts for these materials to ensure sufficient supply and competitive costs. Labour is also a significant component of the manufacturing costs, with approximately 50% of our chemicals' workforce being unionized. We have active collective agreements in place at all of our unionized plants.

North America

We manufacture sodium chlorate at five facilities in North America: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; Amherstburg, Ontario; and Beauharnois, Quebec. We also manufacture chlor-alkali products at North Vancouver, British Columbia.

The pulp and paper industry consumes approximately 95% of sodium chlorate production in North America. Our North American sodium chlorate production is marketed to numerous pulp and paper mills under multi-year contracts that contain price and volume provisions. Approximately 28% of this production is sold in Canada and the remainder is sold in the US, with a small component marketed offshore. In 2002, we completed an expansion of our Brandon plant in Manitoba. Our Brandon, Manitoba plant is one of the lowest cost sodium chlorate facilities in the industry. We are currently expanding this facility by 33% to 260,000 tonnes per year to replace higher cost capacity idled in 2002 at Taft, Louisiana. When complete in the fourth quarter of 2004, this expansion will make Brandon the largest sodium chlorate facility in the world, significantly enhancing our competitive position in North America. In 2002, we idled our Taft, Louisiana plant due to high operating costs and in 2003 we transferred those assets to Brandon as part of the new expansion. Sodium chlorate production capacity in North America decreased in 2003 as a result of this idling. Capacity will increase in the fourth quarter of 2004 once our Brandon expansion is complete.

Our chlor-alkali facility in British Columbia manufactures caustic soda, chlorine and muriatic acid. In British Columbia, almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the polyvinyl chloride, water purification and petrochemicals industries, primarily in the United States.

Brazil

In December 1999, we acquired a 39,000 short-ton per year sodium chlorate plant and a 35,000 short-ton per year chlor-alkali plant in Brazil from Aracruz Cellulose S.A., the leading manufacturer of pulp in Brazil. Substantially all of our production is sold to Aracruz under a long-term sales agreement that has an initial six year take-or-pay component. In 2002, we completed an expansion of both the chlorate and chlor-alkali facilities to meet Aracruz's expansion needs. This expanded the chlorate production capacity by 70% and the chlor-alkali capacity by 35%.

ADDITIONAL FACTORS AFFECTING BUSINESS

See Item 7 of this Form 10-K.

Government Regulations

Our operations are subject to various levels of government controls and regulations in the countries in which we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, all of which are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. However, we do participate in many industry and professional associations and otherwise monitor the progress of proposed legislation and regulatory amendments.

Environmental Regulations

Oil and Gas Operations

Our oil and gas operations are subject to government laws and regulations designed to protect the environment in the countries where we operate. We believe that our operations comply in all material respects with applicable environmental laws. From time to time, we may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

Canada

In Canada, these provisions, which are implemented principally by Environment Canada, Transport Canada and comparable provincial agencies, govern the management of hazardous waste, the discharge of pollutants, the construction of new discharge sources and the transportation of dangerous goods. The laws generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

United States

In the United States, these provisions, which are implemented principally by the United States Environmental Protection Agency, the Department of Transportation, the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters, the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

Yemen

In Yemen, the Yemen Environmental Protection Law was ratified by Parliament and issued by Presidential decree in October 1995. Yemen Republican Decree No. 11 in respect of Protection of the Maritime Environment from Pollution was passed in 1993 and establishes the Public Corporation for Maritime Affairs as the regulatory authority for maritime activities. Under the terms of an agreement with the Government of Yemen in March 1996, we prepaid the dismantlement and site restoration costs on the Masila Block Development Project, and were released from any further obligation relating to these costs on this block.

Nigeria

In Nigeria, we have a risk service contract on Block OML-109 with an indigenous company. The indigenous company is responsible for obtaining all regulatory approvals associated with development in Nigeria. Pollution control regulations in oil and gas operations are governed by the Principal Legislation of Petroleum Act 1969. The regulations are made pursuant to section 8(i)b(iii) of the Petroleum Act which empowers the Minister of Petroleum Resources to make regulations for the prevention of pollution of water sources and the atmosphere. In 1981, the Department of Petroleum Resources (DPR) issued interim guidelines concerning the monitoring, handling, treatment, and disposal of effluents, oil spills and chemicals, drilling muds and cuttings by leases/oil operators. Tentative allowable limits of waste discharges into fresh water, coastal waters and offshore areas of operations were established. The guidelines were updated in 2002 as the Environmental Guidelines and Standards for the Petroleum Industry in Nigeria (EGASPIN).

In November 1999, the Federal Ministry of the Environment (FME) announced that, pursuant to the Environmental Impact Assessment (EIA) Decree No. 86 of 1992, they have been charged with full responsibility for supervising all aspects of the environmental management of the oil and gas industry, replacing the environment division of the DPR and the defunct Federal Environmental Protection Agency. The timing and implications of these changes have yet to be determined.

Accordingly, approvals are usually required from the DPR and the FME for all aspects of environmental management of the oil and gas industry.

Australia

In Australia, the offshore petroleum industry is regulated by two environmental regimes: firstly, broadly consistent, petroleum industry specific, Federal (Commonwealth) and State/Territory legislation; and secondly, a non-industry specific, Federal regime.

The States and Northern Territory have jurisdiction over their onshore petroleum operations, including petroleum within coastal waters. Petroleum operations beyond three nautical miles from the territorial sea baseline are subject to the Commonwealth Petroleum (Submerged Lands) Act 1967 (P(SL)A). The main environmental regulations are the P(SL)A Management of Environment regulations, 1999, and the Dept of Environment & Heritage, (DEH), (formerly Environment Australia), Environment Protection, Biodiversity, & Conservation (EPBC) Act. In July of 2000, the EPBC Act became law. The EPBC Act requires separate documentation to that required under the P(SL)A, and while the two Acts have similar objectives, the processes are quite different.

Under the EPBC Act, operators are required to assess their projects to determine whether an action is likely to have a significant impact on matters of national environmental significance, and make a decision respecting submission of that assessment to a public referral process.

Under the P(SL)A, there are two administrative decision-making bodies in respect of each offshore area; a Joint Authority, (which is the principal decision-making body), comprising the Commonwealth Minister responsible for resources, and the equivalent State or Northern Territory Minister, and a Designated Authority, which handles the day-to-day administrative matters relating to petroleum activities in the defined area. Titleholders under the P(SL)A are responsible for all petroleum related activities (including safety & environment matters) in the permit/licence area. The designated representative of the titleholder is the operator.

Colombia

In Colombia, operations are subject to environmental regulations under the Ministry of the Environment. Community consultation is regulated by the Ministry of the Interior. The basic process, which results in an average time to receipt of license of between four months and two years, starts with the Ministry of Interior requirements for community consultation, followed by preparation of the required environmental impact assessment and management plans, followed by review within the Ministry of the Environment and the regional environmental authorities. Recent attempts to streamline the issuance of hydrocarbon licenses have resulted in some process improvements.

Kyoto Protocol
For a discussion of the Kyoto Protocol, see the Business Risk Management section in Item 7.

Syncrude Operations
Syncrude is regulated by the Alberta Energy and Utilities Board (AEUB) and the Alberta Department of Environment (AENV). In 1999, the AEUB extended Syncrude's operating term through 2035 giving the flexibility required for ongoing orderly development of the operation and reclamation of the site. The AENV issued its approval under the Alberta Environmental Protection and Enhancement Act effective December 21, 1995. The approval has been extended beyond the original 10-year period such that it now expires December 31, 2006, and is a consolidated document covering air, land, water, and waste management matters. Land reclamation is proceeding at a rate of approximately 270 hectares per year, thereby minimizing annual future reclamation costs.

Chemicals Operations
We maintain an active environmental and safety program at our chemicals sites to further our goal of excelling as a Responsible Care® Organization. Our chemicals facilities have completed quantitative risk assessments to assist both the facilities and the communities in their emergency response and risk management plans. The results of these reviews have been communicated to each respective community.

Since 1972, our North Vancouver facility has been the British Columbia regional control center for the North America Chlorine Emergency Plan (CHLOREP). Through this plan, we participate with other chlorine producers to provide professional and responsive action in the event of a chlor-alkali related emergency anywhere in their region of responsibility.

We have taken an active role in the Canadian Chemical Producers' Association (CCPA), CAER (Community Awareness and Emergency Response) and TRANSCAER (Transportation CAER) projects. In 1989, we and other members of the CCPA expanded the CAER and TRANSCAER programs to the Responsible Care® initiative. This initiative is based on the industry's commitment to the responsible development, manufacture, transportation, handling, distribution, use and ultimate disposal of chemicals so as to minimize adverse effects on people and the environment. We successfully completed the CCPA's Round 1 Responsible Care® verification process in 1995. In 1998, we were the first company to undergo Round 2 verification of our Responsible Care® management systems. In 2002, we completed a CCPA Round 3 Responsible Care® reverification.

Regulations that apply to our pulp and paper customers are significant to our chemicals operations. In January 1992, the Province of British Columbia amended the *Pulp Mill and Pulp and Paper Mill Liquid Effluent Control Regulation* to require all British Columbia pulp mills to achieve a zero AOX (Absorbable Organic Halogens) effluent discharge standard from their bleaching processes by the end of 2002. In June 2002, the Province of British Columbia announced that it would amend the Regulation to require all British Columbia pulp mills to meet a new effluent discharge standard of 0.5 kilogram/Air Dried tonne AOX annual average. Currently, all British Columbia pulp mills are complying with the new standard.

Operations in the United States are also subject to various federal and state laws and regulations which govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters, the construction of new discharge sources, and the manufacture, sale and disposal of chemical substances.

The Aracruz facility in Brazil operates in accordance with a number of federal and state laws and regulations, as well as a new civic environmental policy for the city of Aracruz. These regulations address various aspects of environmental management, including environmental zoning for industrial applications, assessment of environmental impacts and licensing of activities that may impact the environment.

Our Brazil chemicals operation is a member of the Brazilian Industrial Chemical Association (ABIQUIM) and is committed to the ABIQUIM Responsible Care initiative. We are currently implementing management systems in Brazil to fulfill the Responsible Care® Codes of Practice, with implementation scheduled for completion in 2004.

For a discussion of the remediation of the site at Squamish, B.C., see the Legal Proceedings section in Item 3.

Other Activities
Our Balzac gas plant and power generation facility received Round 1 Responsible Care® verification in 2002. This is the first oil and gas plant in the world to implement Responsible Care® - an initiative originally found only in chemical facilities.

Environmental Provisions and Expenditures

At December 31, 2003, $197 million has been provided in the accounts for future dismantlement and site restoration costs, which are currently estimated at approximately $514 million for all of our oil and gas and chemicals facilities. During 2003, we recorded a provision for future dismantlement and site restoration costs of $38 million.

During 2003, our capital expenditures for environmental-related matters, including environment control facilities, were approximately $21 million. Our operating expenditures for environmental-related matters were approximately $6 million. Environmental related capital expenditures in 2004 are expected to be similar to 2003.

EMPLOYEES

We had 2,875 employees on December 31, 2003.

Information on our executive officers is presented in Item 10 of this report.

Item 3. Legal Proceedings

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect upon our consolidated financial position or results of operations. Nexen believes it has made adequate provisions for such lawsuits and claims.

Nexen received an order on February 17, 1999, under the British Columbia Waste Management Act to conduct a comprehensive remediation program, including soil and ground water remediation, with respect to our former chlor-alkali plant site at Squamish, British Columbia. The Order is within the scope of contemplated and accrued environmental remediation requirements for the former plant site and does not constitute a fine or penalty upon Nexen. We are in compliance with the Order as the land has been remediated and we have submitted a final report.

Nexen's US operations have received, over the years, notices and demands from the United States Environmental Protection Agency, state environmental agencies, and certain third parties seeking to require investigation and remediation under federal or state environmental statutes. Although no assurances can be made, we believe our US operations are protected from any present or future material liabilities that may arise from these sites because of Assumption and Indemnification Agreements in place.

A subsidiary of Occidental Petroleum Corporation (Occidental) has initiated a request for arbitration at the International Court of Arbitration of the International Chamber of Commerce regarding an Area of Mutual Interest Agreement (Agreement) in the Republic of Yemen. Pursuant to the Agreement, if Nexen proposed to conduct petroleum development operations within two small areas of Block 51 in the Republic of Yemen (Heijah/Tawila Extension Lands), then we were to offer Occidental the right to acquire 50% of its interest in those areas. The Agreement expired on March 12, 2003, with Nexen not having proposed any such operations. Occidental seeks a claim for declaratory relief under the Agreement, claims compensation for breach of contract (50% of the net profits earned or to be earned from the Heijah/Tawila Extension Lands), plus interest and costs. Since the expiry of the Agreement, we commenced exploration activities within Block 51, including the Heijah/Tawila Extension Lands and, in December 2003, filed a notice of commercial discovery with the Yemen government. Given that the agreement expired without Nexen having proposed to conduct petroleum development operations, we believe Occidental's claim is without merit and we intend to vigorously defend our contractual rights.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2003.

PART II

Item 5. Market for the Registrant's Common Shares and Related Stockholder Matters

Nexen's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol NXY.

On December 31, 2003, there were 1,420 registered holders of common shares and 125,606,107 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings.

Trading Range of Nexen's Common Shares

($/share)	Toronto Stock Exchange		New York Stock Exchange	
	High	Low	High	Low
	(Cdn $)		(US $)	
2003				
First Quarter	34.85	29.30	22.55	19.89
Second Quarter	35.59	28.26	26.31	19.75
Third Quarter	39.68	33.02	29.00	24.03
Fourth Quarter	47.08	36.65	36.47	27.32
2002				
First Quarter	39.75	29.70	25.11	18.57
Second Quarter	42.50	37.20	28.04	23.30
Third Quarter	42.18	34.34	27.71	21.70
Fourth Quarter	37.78	31.00	23.85	19.79

Quarterly Dividends on Common Shares ($/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2003	0.075	0.075	0.075	0.100
2002	0.075	0.075	0.075	0.075

Payment date for dividends was the first day of the next quarter.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. In accordance with the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian" (as defined) file notice with Investment Canada and obtain government approval prior to acquiring control of a "Canadian business" (as defined). Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities.

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. The Plan creates a right, which attaches to each present and future outstanding common share. Each right entitles the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the common shares and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our Board can defer the separation date.

The Plan creates a right, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), for each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2005 to remain effective past that date.

Item 6. Selected Financial Data

Five Year Summary of Selected Financial Data in Accordance with US GAAP

(Cdn$ millions)	2003	2002	2001	2000	1999
Results of Operations					
Net Sales [1]	2,908	2,506	2,497	1,533	1,411
Net Income from Continuing Operations	475	338	348	493	62
Basic Earnings per Common Share from Continuing Operations ($/share)	3.83	2.77	2.89	3.94	0.45
Diluted Earnings per Common Share from Continuing Operations ($/share)	3.80	2.73	2.85	3.88	0.45
Net Income	420	352	365	522	63
Basic Earnings per Common Share ($/share)	3.39	2.88	3.03	4.17	0.46
Diluted Earnings per Common Share ($/share)	3.36	2.84	2.99	4.12	0.46
Production – Before Royalties (mboe/d) [2]	269	269	268	256	239
Production – After Royalties (mboe/d) [2]	185	176	184	171	163
Financial Position					
Total Assets [2]	7,703	6,764	5,609	5,874	4,922
Long-Term Debt [3,4]	2,472	2,575	2,242	2,238	1,997
Shareholders' Equity	2,131	1,812	1,414	1,050	1,130
Capital Expenditures	1,494	1,625	1,404	915	612
Dividends per Common Share ($/share) [5]	0.325	0.30	0.30	0.30	0.30
Common Shares Outstanding (thousands) [6]	125,606	122,966	121,202	119,855	138,145

Notes:

1 During 2003, we sold non-core conventional light oil assets in southeast Saskatchewan in Canada producing 9,000 bbls/d. The results of these operations are shown as discontinued operations as described in Note 9 of our Consolidated Financial Statements.

2 In 1999, production and total assets decreased as we sold our North Sea assets and certain producing assets in Canada. These North Sea assets were producing 34 mmcf/d of gas and the Canadian assets were producing 40 mboe/d. In 2000, production increased as additional development wells were brought on stream in Yemen and Buffalo in Australia began producing. In 2003, production increased from our deep-water Aspen development in the Gulf of Mexico in the US.

3 In February 2004, $575 million of Long-Tem Debt was repaid. At December 31, 2003, this amount was included in the current portion of Long-Term Debt on the balance sheet.

4 Under US GAAP, our Long-Term Debt, net of working capital, of $1,662 decreased by $848 million during 2003.

5 Quarterly dividends were increased to 10¢ in the fourth quarter of 2003.

6 During 2000, we entered into an agreement to repurchase 20 million Nexen common shares.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

TABLE OF CONTENTS

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of the significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 16 to the Consolidated Financial Statements.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Our discussion and analysis of our oil and gas activities with respect to oil and gas volumes, reserves and related performance measures is presented on a working interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

Note: Canadian investors should read the Special Note to Canadian Investors on page 60 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

EXECUTIVE SUMMARY OF 2003 RESULTS

(Cdn$ millions)	2003	2002	2001
Net Income	639	452	450
Earnings per Common Share ($/share)	4.84	3.34	3.40
Cash Flow from Operations [1]	1,859	1,383	1,423
Production, before royalties (mboe/d) [2]	269	269	268
Production, after royalties (mboe/d)	185	176	184
Capital Expenditures	1,494	1,625	1,404
Proved Reserve Additions, net (mmboe) [2]	38	126	131
Finding and Development Costs ($/boe) [3]	11.64	12.41	9.24
Net Debt [4]	1,377	1,775	1,460
Net Debt to Cash Flow (times) [5]	0.8	1.4	1.1

We achieved record financial results in 2003. As the variance table on page 33 shows, the three biggest drivers impacting net income growth were higher-margin volumes primarily in the US, strong oil and gas prices and exceptional marketing results. A strengthening Canadian dollar and an impairment charge largely attributable to heavy oil assets reduced these gains. Overall net income grew 41% over 2002 to $639 million and our cash flow from operations reached a record $1.9 billion.

Crude oil prices remained strong in 2003 as supply and demand fundamentals supported higher prices. Instability in the Middle East, growing demand and low inventory levels kept average WTI at US$31.04/bbl. Natural gas prices peaked during the first quarter of the year and again in December, tracking weather patterns in the US. Our marketing group was positioned to take advantage of these fluctuations, benefiting from price differences between the west and the east, as well as between the summer and winter months.

The strengthening Canadian dollar relative to the US dollar reduced our net income by $130 million and cash flow from operations by $250 million. This is because our foreign revenues and realized commodity prices, referenced in US dollars, were lower when translated to Canadian dollars. However, we benefit to the extent that our foreign operating costs and capital expenditures are also reduced when translated. In addition, most of our fixed-rate debt is denominated in US dollars so this debt is reduced with a strengthening Canadian dollar.

As a result of certain negative reserve revisions in Canada, our net income includes a non-cash impairment charge of $175 million, after-tax, of which almost 90% relates to heavy oil reserves. The revisions resulted from changes to late field-life economic assumptions, a reduction in proved undeveloped reserves based on drilling results and geological mapping, and reassessments of expected future production profiles. The reduction does not affect our production forecast for 2004. Our Canadian oil and gas properties will continue to be a significant source of free cash flow for future investment since the future estimated cash flow from our total conventional Canadian assets is approximately 2.5 times their related carrying value.

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[1] We evaluate our performance and that of our business segments based on earnings and cash flow from operations. Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other. We consider it a key measure as it demonstrates our ability and the ability of our business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt.

(Cdn$ millions)	2003	2002	2001
Cash Flow from Operating Activities	1,469	1,322	1,566
Changes in Non-Cash Working Capital	320	46	(143)
Other	70	15	-
Cash Flow from Operations	1,859	1,383	1,423

[2] Production, before royalties and reserves include our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies. We have used our year-end pricing assumptions.

[3] Finding and Development Costs is defined as oil and gas exploration and development expenditures divided by total proved reserves additions on a before-royalties basis, prior to acquisitions, dispositions and revisions. Proved reserves include our working interest before royalties.

[4] Long-term debt less net working capital.

[5] Net debt divided by cash flow from operations after dividends on Preferred Securities.

High-margin barrels from Aspen and now Gunnison replaced declining production in North America and at Buffalo, offshore Australia and Ejulebe, offshore Nigeria - both of which will be fully depleted in 2004. Canada's production was reduced mid-year as we disposed of 9,000 boe/d of non-core light oil properties in southeast Saskatchewan. The revenues and expenses associated with these disposed properties are segregated as discontinued operations in our financial statements. The shift from low-margin production in maturing areas to high-margin production in new growth areas grew overall production after royalties by 5% despite flat production before royalties. In 2004, we expect production before royalties to average between 255,000 and 275,000 boe. Production after royalties will continue to grow with more low-royalty volumes from Gunnison and Aspen.

In 2003, we continued our strategy of growing long-term value primarily through grassroots exploration and development. We focused on maximizing returns from our capital investment program growing value beyond simply adding production volumes. Targeting higher returns, we have shifted our capital investment away from higher-cost, maturing North American conventional production into four key basins with significant growth projects as described in Item 1 of this 10-K. Below are highlights of our strategic progress in 2003:

One-third of our total $1.5 billion capital budget was invested in the Gulf of Mexico, now our largest cash flow contributor. We advanced our deep-water strategy in 2003 by acquiring the remaining 40% interest in Aspen and becoming operator of our first deep-water project. Aspen's low cost and low royalty production generated cash netbacks of US$23 per boe, nearly twice our corporate average. We added to Aspen's high-margin production by bringing our second deep-water project, Gunnison, on stream ahead of schedule in December 2003. Production is ramping up at Gunnison through 2004 and we expect to tie-in a third development well at Aspen, adding to our improving margins. Exploration continues in 2004 on acreage in the Aspen and Gunnison areas, the eastern Gulf and the shelf deep-gas trend.

In 2003, we invested $253 million in the Middle East: 87% on development and exploitation at Masila and the remainder on exploration on Block 51, adjacent to Masila, and in northern Yemen. Activities at Masila were focussed on maintaining existing production rates. Extensions to Masila's Heijah and Tawila fields and appraisal of Block 51 discoveries contributed 63 mmboe of proved reserves in 2003. In 2004, we plan additional delineation drilling on Block 51 to establish even more reserves. With new production from Block 51 planned for 2005, we expect to maintain strong production rates from Yemen for several years.

We invested $57 million to continue building our presence offshore West Africa. On Block 222, offshore Nigeria, three appraisal wells at Usan delivered very good results. In addition, one appraisal well was drilled at Ukot. A development plan is being prepared for submission to the Nigerian government. Exploration will continue on this block as well as on OML-115, offshore Nigeria and Block K, offshore Equatorial Guinea - both attractive new prospects we acquired during 2003. To date, we have not booked any proved reserves for our Block 222 discoveries. Proved reserves will be booked once commercial development is approved.

Our $96 million investment in the Long Lake project in the Athabasca oil sands allowed us to continue detailed engineering, implement a SAGD pilot, and obtain regulatory approval for the commercial project in 2003. With Board sanctioning of the commercial project in February 2004, we have booked 200 million barrels of proved reserves in 2004. Only 3 million barrels of proved reserves were booked in 2003 related to the SAGD pilot. Construction of commercial facilities will begin this summer. In 2003, we also invested $173 million in Syncrude's Stage 3 expansion, which together with base operations added 26 million barrels of proved reserves at a cost of $7.38 per boe. We expect this expansion to be completed in 2005, adding 8,000 barrels per day of new production to Nexen.

Beyond these four basins, capital was invested in our core assets in Canada and the shallow-water Gulf, in Colombia and in our chemicals operations as we expand our Brandon facility and transfer sodium chlorate capacity there from our Taft, Louisiana plant. In Canada, our exploration and development programs in Canada added 16 mmboe of conventional proved reserves.

Overall, we added 38 mmboe of net proved reserves as follows:

(mmboe)	
Additions (Extensions and Discoveries)	111
Acquisitions (Aspen)	24
Dispositions (primarily southeast Saskatchewan)	(30)
Revisions (primarily in Canada)	(67)
	38

Additions of 111 mmboe of proved reserves replaced 113% of our production at a finding and development (F&D) cost of $11.64 per boe. Our F&D costs have trended upwards over the past few years given the long-lead times associated with our new growth projects. These projects consume large amounts of capital and mismatches are created in the timing of reserve recognition. Over their lives these projects are expected to generate attractive returns and low full-cycle F&D costs.

In 2003, we took steps to improve our liquidity and financial flexibility to ensure we are able to fund our multi-year development projects. Record cash flow, disposition proceeds and a strong Canadian dollar reduced net debt and preferred securities by $758 million. Net debt and preferred securities at year-end was 1.0 times cash flow. We also took advantage of the low interest rate environment and issued US$960 million of public debt, enabling us to fund debt maturities, retire our preferred securities and reduce future financing costs.

Going forward, we are well positioned for growth. Our 2004 oil and gas capital program of $1.7 billion will continue to support progress on our major development projects and fund an active exploration program, half of which is directed to US exploration. Strong commodity prices are likely to continue partially offset by the impact of a strong Canadian dollar on our US-dollar denominated revenues. Removing the impact of price and exchange rate fluctuations, we expect our improving margins in the US to grow our cash flow from operations by 10% year-over-year.

CAPITAL INVESTMENT

(Cdn$ millions)	**2003**	**2002**	**2001**
Capital Investment			
New Growth Exploration	329	259	411
New Growth Development	358	626	110
Core Asset Development	589	592	641
Property Acquisition	164	4	122
Total Oil & Gas	1,440	1,481	1,284
Chemicals, Marketing and Other	54	144	120
Total	1,494	1,625	1,404

Our capital programs are focused on maximizing returns on every dollar of capital invested. Investment dollars are allocated between:

- core assets for short-term growth and free cash flow to fund ongoing capital programs;
- development projects that convert our discoveries into new production and cash flow; and
- exploration projects for longer-term growth.

Given our exploration success over the past several years, we have made significant investments in major development projects in our four key basins. In 2001, we invested in new development projects at Aspen and Gunnison in the deep-water Gulf of Mexico and Syncrude's Stage 3 expansion. In 2002, we continued developing these projects and began scoping out our Long Lake project. We also made discoveries at Usan offshore Nigeria. In 2003, the first of these projects, Aspen came onstream. We converted the discoveries on Block 51 in Yemen into a development project. Late in 2003, our second deep-water project at Gunnison came onstream, with cash netbacks that are twice our corporate average.

While our deep-water Gulf investments are already contributing high-value production, driving our corporate margins, our growth projects in the other basins have yet to contribute production and cash flow. Most of these are long-lead time projects, with three to five years between discovery and first production. Although these large capital investments have yet to generate cash flow, the capital invested is not at risk. Over their lives, these projects are expected to generate attractive returns and low full-cycle finding and development costs.

The results of our capital programs are detailed below.

2003 Capital

In 2003, we invested over $1.4 billion in oil and gas with:

- 41% in core assets to maintain existing production levels;
- 36% in new growth development projects, and;
- 23% in new growth exploration projects.

(Cdn$ millions)	Development	Exploration	Other	Total
Oil and Gas				
United States	249	147	164	560
Yemen	219	34	-	253
Nigeria	-	35	-	35
Canada	259	51	-	310
Syncrude	195	-	-	195
Other Countries	25	62	-	87
	947	329	164	1,440
Chemicals	-	-	24	24
Marketing, Corporate and Other	-	-	30	30
Total Capital	947	329	218	1,494

In 2004, we plan to invest almost $1.7 billion in oil and gas with:

- 35% in core assets to maintain existing production levels;
- 45% in new growth development projects, and;
- 20% in new growth exploration projects.

2004 Estimated Capital

(Cdn$ millions)	Development	Exploration	Other	Total
Oil and Gas				
United States	175	158	-	333
Yemen	397	23	-	420
Nigeria	19	59	-	78
Canada	130	52	-	182
Long Lake Synthetic	391	9	-	400
Syncrude	182	-	-	182
Other Countries	17	60	-	77
	1,311	361	-	1,672
Chemicals	-	-	53	53
Marketing, Corporate and Other	-	-	41	41
Total Capital	1,311	361	94	1,766

Gulf of Mexico

Aspen

Our deep-water Gulf of Mexico strategy began paying off in 2003. After bringing Aspen on-stream in December 2002, a record 19 months after discovery, we acquired the remaining 40% interest in March 2003 from BP for $164 million. With 100% interest in Aspen, we are now deep-water operators and control the timing of future exploration and development on our acreage in the Greater Aspen area. Aspen's production has low royalties and operating costs, resulting in high-margin production that has already recovered approximately 55% of our investment of US$374 million. A third development well is drilling at Aspen.

Gunnison

In 2003, production from our second deep-water project at Gunnison, discovered in 2000, came on-stream. Gunnison's SPAR production facility was completed and moved from Finland to the Gulf mid-summer. We installed the remaining equipment on the production platform, and completed and tied-in the subsea wells. Production came on-stream in December 2003. Gunnison will deliver equally attractive returns as Aspen, with its low royalties and operating costs.

Exploration
In 2003, we drilled three exploration wells in the Gulf, including a deep-water dry hole at Santa Rosa. Under our first exploration venture with Shell, we have recently finished drilling the Shark prospect on the shelf in search of natural gas in deep shelf sands. No commercial hydrocarbons were encountered and the well is temporarily abandoned while we evaluate the data collected from the well bore.

In 2003, we entered into a second exploration venture with Shell to jointly explore a 1,116 square mile area of the deep-water eastern Gulf of Mexico. The area includes 124 blocks located in Mississippi Canyon and Desoto Canyon. Under this exploration venture, we drilled the Shiloh-1 well on Desoto Canyon 269 to a total depth of over 24,000 feet. At Shiloh, we encountered hydrocarbons in non-commercial quantities so the well was written off. We have acquired additional acreage in the area and will continue drilling in hopes of proving-up commercial quantities in the region.

In 2004, almost half our exploration capital will be invested in the Gulf of Mexico. Our plans include five high-potential exploration wells: two deep shelf gas prospects on the shelf, Crested Butte offsetting Aspen, a well in Garden Banks, and another in the eastern Gulf of Mexico.

Middle East

Masila
Our primary focus at Masila is to maintain production rates. During 2003, we invested $219 million to drill 94 development wells, construct new facilities, increase water handling capabilities, and perform additional workovers to maintain production rates. We plan to spend US$176 million in 2004 on development projects in the Masila field to drill 90 wells and complete facility enhancements to partially offset the field's natural decline.

Block 51
In 2003, we enjoyed exploration success with discoveries in the Baishir al Khair Field (BAK) at BAK-A (formerly Tammum) and BAK-B (formerly Amir). Seven appraisal wells were drilled, encountering oil in the Qishn and Saar horizons, and we began commercial development late in the year. Initial development includes completing the seven wells drilled, ten new development wells, a central processing facility, a gathering system and a tieback to our Masila export system. Based on drilling results to date, we expect to develop in excess of 60 million barrels of reserves and add between 20,000 and 25,000 barrels per day of production capacity in early 2005. The field has additional potential that will be quantified by a 3D seismic program and further delineation drilling in 2004. We are continuing to explore the Block and plan to drill at least six exploration wells in 2004.

Exploration
In addition to Block 51, we drilled the Husan El Kradis (HEK-1R) exploration well 25 kilometres northwest of BAK-B to test for oil in fractured basement; however, the well was dry. Further exploration is planned in the area.

Offshore West Africa

Nigeria
In 2003, we focused on developing our Usan and Ukot discoveries on Block OPL-222. We drilled three appraisal wells at Usan and announced a significant extension of that field. An additional appraisal well at Ukot was also drilled. The operator is preparing a field development plan for submission to the Nigerian government for approval and we expect first production around 2008. In 2004, we plan additional exploration drilling to test the Block's remaining potential.

In December 2003, as part of our initiative to expand our position in West Africa, we were assigned an interest in OML-115 offshore Nigeria. We commenced a program to acquire 410 km^2 of 3D seismic data over the block and plan to drill one exploration well in 2004.

Equatorial Guinea
We acquired a 25% interest in Block K located 100 km offshore. The Block is on trend with the 300-million barrel Ceiba field and other discoveries on Block G to the north. In 2004, we plan to drill two wells to assess Equatorial Guinea's ability to contribute to the growth of our West Africa region.

Athabasca Oil Sands

Syncrude

In 2003, the Stage 3 expansion proceeded as expected. The Aurora 2 bitumen train was completed and successfully placed in production. The upgrader expansion at Mildred Lake is 35% complete, on-track for start-up in 2005. We expect the Stage 3 expansion to increase our share of production to over 25,000 barrels per day. Due to higher engineering, manufacturing and construction costs, the estimated costs of the Stage 3 expansion have increased from initial estimates of $4.1 billion ($296 million net) to $5.7 billion ($412 million net). Activities in 2004 will also focus on replacing bitumen production capacity that will be lost when the southwest quadrant of the Mildred Lake Base Mine is depleted.

Synthetic Oil at Long Lake

The Long Lake project is progressing rapidly. In 2003, we commenced pilot testing of SAGD technology at Long Lake, obtained Alberta Energy Utilities Board approval and completed more than 15% of the detailed engineering.

On February 12, 2004, our Board of Directors approved the Phase 1 commercial development plan. The project will develop approximately 10% of our Athabasca bitumen resource, upgrading this bitumen into high-quality light, sweet synthetic crude oil. As a result of the approval, we have booked 200 million barrels of proved reserves in 2004.

In 2004, we expect to continue with detailed engineering, order long-lead time equipment and commence construction at Long Lake to meet a 2006 start-up date for bitumen production and a 2007 start-up date for synthetic crude oil production. Gross capital costs are expected to total $3.4 billion.

Other Exploration and Core Asset Development

Canada – Conventional

As our conventional assets in Western Canada mature, we are focusing on projects that provide the highest return on invested capital. In 2003, we sold over 9,000 barrels of daily production at attractive prices. We've also continued our transition to new sources of production growth such as synthetic crude oil and coal bed methane.

Canada – Exploration

We increased our coal bed methane (CBM) land holdings and proceeded with our Corbett pilot, drilling 24 wells. In 2004, we will significantly expand the size of our CBM pilot project at Corbett and expect to decide on commerciality by year-end. We will test four other Upper Mannville CBM prospects and drill a number of gas exploration well in the Alberta foothills.

Colombia

In 2003, we drilled 31 development wells to increase production rates and test the viability of a waterflood program on the Guando field. In 2004, we plan to drill 24 development wells and implement a full-field waterflood at Guando.

We continued exploration in Colombia. One exploration well drilled on the Andino Block tested wet and was abandoned.

Chemicals

During 2003, we focused on increasing reliability and cost reduction at all of our manufacturing facilities. We also began relocating the assets from our Taft facility in Louisiana to Brandon, Manitoba, the lowest-cost sodium chlorate production facility in North America. In 2004, we expect to complete our Brandon expansion including the relocation and installation of the Taft assets. Upon completion of this expansion, the Brandon plant will be the largest sodium chlorate plant in the world.

Marketing, Corporate and Other

Capital spending in 2003 and planned spending in 2004 includes systems development, computer hardware and software, office equipment and leasehold improvements.

FINANCIAL RESULTS

Year to Year Change in Net Income

(Cdn$ millions)	2003 vs 2002	2002 vs 2001
Net Income for 2002 and 2001	452	450
Favourable (unfavourable) variances:		
Cash Items:		
Production volumes, net of royalties:		
Crude oil	92	30
Natural gas	41	(18)
Change in inventory - crude oil sales, net of royalties	(25)	-
Realized commodity prices:		
Crude oil	41	183
Natural gas	234	(113)
Oil and gas operating expense:		
Conventional	37	(63)
Synthetic	(14)	5
Marketing contribution	96	(23)
Chemicals contribution	(5)	1
General and administrative	(38)	(16)
Interest expense	4	3
Current income taxes	13	(7)
Other	-	(22)
Total Cash Variance	476	(40)
Non-Cash Items:		
Depreciation, depletion and amortization:		
Oil and Gas	(327)	(80)
Other	(5)	(10)
Exploration expense	(19)	79
Future income taxes	28	79
Other	34	(26)
Total Non-Cash Variance	(289)	42
Net Income for 2003 and 2002	639	452

Significant variances in net income are explained in the sections that follow.

OIL AND GAS

Production

	2003		2002		2001	
	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
Oil and Liquids (mbbls/d)						
Yemen	116.8	57.5	118.0	55.8	118.3	55.5
Canada [1]	46.3	35.4	56.3	43.4	58.0	48.3
United States	28.3	25.0	9.9	8.2	10.0	8.3
Australia	6.1	5.6	12.8	10.3	10.2	9.6
Other Countries	5.4	4.6	8.9	5.2	6.2	5.3
Syncrude	15.3	15.2	16.6	16.5	16.1	15.5
	218.2	143.3	222.5	139.4	218.8	142.5
Natural Gas (mmcf/d)						
Canada [1]	158	125	167	128	174	147
United States	145	122	112	93	121	99
	303	247	279	221	295	246
Total (mboe/d)	269	185	269	176	268	184

Note:
[1] Includes the following production from discontinued operations. See Note 9 to our Consolidated Financial Statements.

(mboe/d)	2003	2002	2001
Production			
Before Royalties	6.2	10.5	11.0
After Royalties	4.6	7.8	8.0

2003 vs 2002 – 5% production growth after royalties added $133 million to net income

Production after royalties grew 5%, with new low-royalty deep-water production from Aspen and more recently Gunnison, and more cost recovery barrels from Masila in Yemen. At Masila, we received a greater percentage of gross production to recover costs we incurred on the government's behalf.

Production before royalties was flat compared to 2002 as growth in our US deep-water production was partially offset by dispositions in Canada, expected production declines offshore Nigeria and Australia, and maturing conventional assets. We expect 2004 production before royalties to average between 255,000 and 275,000 boe - similar to 2003 levels. Production after royalties will continue to grow with more low-royalty volumes from Gunnison and Aspen.

MASILA BLOCK IN YEMEN

Production before royalties decreased slightly in 2003 consistent with the overall decline in the field's base production. As Masila matures, we continue to drill more development wells, perform more workovers and expand our water handling capacity to manage the declines. Late in 2003, our expanded drilling and workover efforts successfully increased production to 120,000 barrels per day (net to us).

While the field's total production decreased in 2003, our share of production after royalties grew due to the cost recovery mechanism in our production sharing contract. We are entitled to recover the costs we have incurred on the government's behalf (up to a 40% limit) through additional production volumes. As recent development drilling, facilities expansion and infrastructure modifications have increased our pool of recoverable costs, we receive a larger portion of total production to recover these costs.

CANADA

Given the maturity of the Western Canadian Sedimentary Basin, production additions are shrinking and declines are increasing. Our conventional Canadian assets are no exception. We aggressively managed our assets by developing them where we could add value or by selling them at attractive prices where we could not. Our conventional volumes in Canada fell 12% excluding the sale of our non-core properties in southeast Saskatchewan. We are investing the free cash flow from our Canadian assets in more profitable, multi-year development projects.

Crude oil production was down 18%. On August 28, 2003, we sold 9,000 boe/d of non-core, light oil properties in the Williston Basin of southeast Saskatchewan for net proceeds of $268 million. The remaining decrease was due to base declines on our heavy oil properties as water cuts increased at Marsden and wells at Edam sanded up.

Our natural gas volumes fell 5% as new production from drilling did not offset the natural decline in our gas properties.

We expect conventional production to decline modestly in 2004 as our asset base matures. However, this trend will reverse as our Long Lake project starts up with the production of bitumen in 2006 and synthetic crude oil in 2007.

GULF OF MEXICO

A full year of deep-water Aspen production increased US production rates 84% to record levels in 2003. Production adds and optimization activities at Eugene Island 295 and Vermilion 76 offset declines on the shelf.

Aspen came on-stream and began delivering high-margin barrels in December 2002. We then acquired the remaining 40% interest in late March 2003. This acquisition contributed 8,000 boe per day at a cash return of $33.11 per boe in 2003. We locked-in a portion of our return on the acquisition by selling approximately 60% of the acquired production forward to March 2004 at a weighted average price of US$29.50 per boe. The forward sale of 10% of the acquired reserves effectively pays for 70% of the purchase price.

Late in 2003, additional deep-water production came on-stream at Gunnison. Three subsea wells were tied-in and were producing 7,200 boe per day at year-end. Our total deep-water production for the year was 24,000 boe per day.

Our shelf production was consistent with 2002 levels as we optimized production where possible. We restored production at hurricane-damaged Eugene Island 295 ahead of schedule in February 2003 and continued to deliver solid rates from our Vermilion 76 development. These gains were offset, in part, by lower performance at Eugene Island 18 and West Cameron 170.

We expect the deep-water Gulf of Mexico to remain our fastest growing area in 2004 with Gunnison production increasing to 17,000 boe per day. We estimate our US production levels will reach over 70,000 boe per day by the end of the year.

OTHER COUNTRIES

Our production at Buffalo offshore Australia and at Ejulebe offshore Nigeria declined as expected throughout 2003 as both fields approach the end of their economic life. We expect final production from both in 2004.

Colombia production grew 131% with 31 new development wells. Our pilot test confirmed the viability of a waterflood and we are moving to full-field waterflood in 2004. We expect to see volumes increase by 50% in 2004.

SYNCRUDE

Production decreased 8% in 2003 as an extra turnaround was completed during the year. A 37-day unplanned coker turnaround reduced volumes in the fourth quarter to 14,800 bbls per day. The turnaround delivered greater operational reliability immediately as we exited 2003 at 19,900 bbls per day. We expect the benefits of this turnaround to continue and do not anticipate a coker turnaround in 2004.

2002 vs 2001 – Higher production added $12 million to net income

Production from our core assets in Yemen, Canada and the US remained largely stable year over year. On-going development activities at Masila in Yemen, at Hay in Canada and on the shelf in the US Gulf of Mexico helped maintain production rates. In the US, poor weather in the third and fourth quarters, including tropical storm Isidore and Hurricane Lili caused the temporary shut-in of production, a 6-week delay at Aspen and damage to our Eugene Island 295 production platform. All production, except Eugene Island 295, was restored in the fourth quarter of 2002. Aspen's first well came on-stream in early December 2002 and the second well in late December.

Our non-core assets made significant contributions during the year. At Buffalo offshore Australia a successful two-well infill drilling program contributed 7,500 boe per day of incremental production. Ejulebe offshore Nigeria contributed a 27% increase as the reservoir continued to perform better than anticipated. Both Buffalo and Ejulebe were declining at year-end as they were approaching the end of their expected lives.

Commodity Prices

	2003	2002	2001
Crude Oil			
West Texas Intermediate (US$/bbl)	31.04	26.09	25.97
Differentials (US$/bbl):			
Masila	3.03	1.41	3.29
Heavy Oil	8.63	6.49	10.68
Mars	3.53	2.51	4.89
Producing Assets (Cdn$/bbl)			
Yemen	39.45	38.80	35.05
Canada	32.37	31.13	24.86
United States	37.68	38.88	38.35
Syncrude	43.36	40.89	39.90
Australia	43.14	40.30	38.71
Other Countries	38.22	38.96	37.37
Corporate Average (Cdn$/bbl)	38.04	37.13	33.10
Natural Gas			
New York Mercantile Exchange (US$/mmbtu)	5.60	3.37	4.00
AECO (Cdn$/mcf)	6.35	3.84	5.97
Producing Assets (Cdn$/mcf)			
Canada	5.64	3.57	5.02
United States	8.16	5.29	6.66
Corporate Average (Cdn$/mcf)	6.85	4.25	5.69
Average Realized Oil and Gas Price (Cdn$/boe)	38.63	35.14	33.28
Average Foreign Exchange Rate			
Canadian to US Dollar	0.7135	0.6369	0.6458

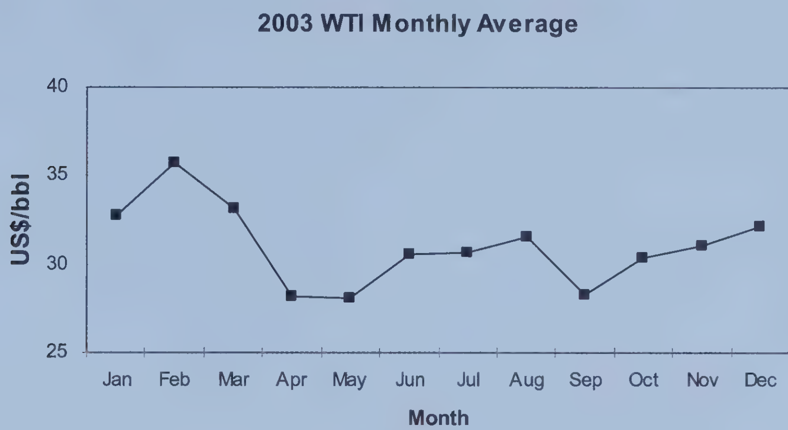
2003 vs 2002 – Higher realized prices added $275 million to net income

Both crude oil and natural gas commodity prices reached near record levels in 2003 as supply and demand fundamentals supported strong prices. The positive impact of strong crude oil and natural gas reference prices was offset in part by the strengthening Canadian dollar and widening crude oil differentials.

All of our oil sales and most of our gas sales are denominated in or referenced to US dollars. As a result, the strengthening Canadian dollar relative to the US dollar reduced our realized crude oil price by $4.50 per bbl and our realized natural gas price by $0.80 per mcf. In total, our net sales decreased $280 million from 2002 levels with the strengthening of the Canadian dollar. The Canadian to US dollar exchange rate closed the year at 77¢.

CRUDE OIL REFERENCE PRICES

Supply and demand fundamentals consistently supported strong reference prices throughout 2003. WTI opened and closed the year around US$33 per bbl, with highs of approximately US$38 per barrel and lows around US$25 per barrel.



Overall, the higher average WTI prices were supported by:

- ongoing concerns over the security and stability of Iraqi production;
- higher political risk in the Middle East;
- labour disputes, and the resulting and threatened supply disruptions, in Nigeria and Venezuela;
- OPEC's determination to hold production quotas in support of their price band;
- growing demand in Asia, particularly China and India;
- low crude oil and product inventories in North America; and,
- the decline in value of the US dollar relative to other major world currencies.

These factors, along with speculation around their severity and duration, created volatility in world crude oil prices. In 2004, analysts expect crude oil prices to fall to between US$25 to US$28, as non-OPEC supply from Russia and Iraq grows. An OPEC production cut, escalated Middle East risk or a greater-than-expected economic recovery would put upward pressure on these forecasts.

CRUDE OIL DIFFERENTIALS

Crude oil differentials widened in 2003 largely in response to the overall strength of WTI.

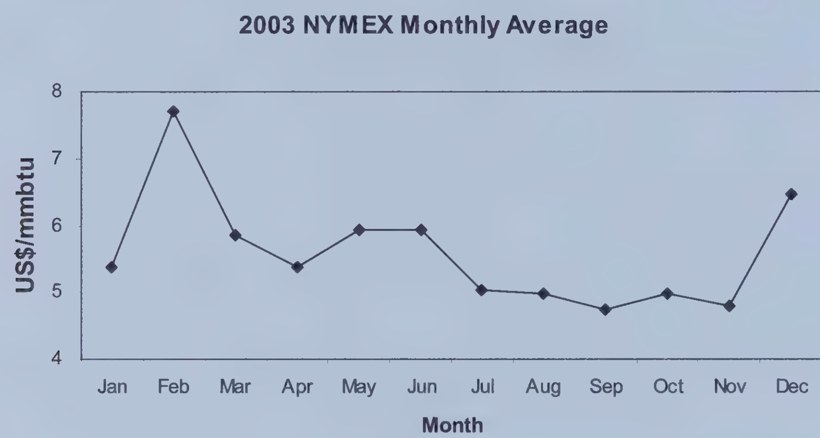
Our Masila differential continued to track the Brent/WTI spread. Despite the strength in WTI during the year, the Brent differential actually remained relatively narrow. Brent prices strengthened with high demand in Europe during the exceptionally warm summer months and growing demand in Asia late in the year. Unexpected platform turnarounds in the North Sea reduced supply, causing the Brent/WTI differential to narrow even further. We expect the Masila differential to remain around US$3 per bbl in 2004.

The wider heavy oil differential was largely due to an overall increase in supply from new Canadian heavy oil projects and some temporary decreases in demand from unexpected refinery turnarounds and the August blackout in parts of eastern North America. The heavy oil differential is expected to remain around US$8 per bbl in 2004.

The Mars differential impacts the pricing of our Aspen production and averaged US$3.53 per bbl. Again, despite the strength in WTI, the Mars differential was relatively narrow in 2003. The pricing of Mars blend is directly affected by the pricing of sour blends. The instability of Iraqi supply and OPEC production cuts improved the pricing of sour blends and allowed the Mars differential to remain narrow.

NATURAL GAS REFERENCE PRICES

North American natural gas prices were exceptionally strong during both the first quarter of 2003 and December 2003. Natural gas prices reached almost US$10 per mcf in the first quarter, but more notably did not dip below US$4.40 per mcf throughout the rest of the year.



Extended cold weather last winter and resulting low storage inventory levels were the major reason for the initial price increase early in the year. Fears of cold weather in the east increased gas prices in December. This also caused the NYMEX/AECO basis to widen significantly late in the year as weather forecasts in the west were suggesting above normal temperatures. We expect natural gas prices to decline to around US$4.25 per mmbtu in 2004.

2002 vs 2001 – Higher realized prices added $70 million to net income

WTI contributed little to cash flow growth in 2002, however narrow crude oil differentials contributed around $180 million. At the beginning of 2002, WTI was US$19.73 per barrel and strengthened to close the year at US$31.20 per barrel. Low inventory levels in Europe kept the Brent/WTI differential narrow throughout most of the year. Given that our Masila crude tends to price off Brent, the Masila differential remained narrow along with the Brent/WTI spread. The heavy oil differential was narrow due to the unexpected disruption of heavy oil supply from Venezuela late in 2002. Lower natural gas prices reduced net income by $113 million. Natural gas prices fell in the first part of 2002 as inventories were high, but increased late in the year as cold weather hit the eastern US.

Operating Costs

(Cdn$/boe)	2003		2002		2001	
	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Conventional Oil and Gas						
Yemen	2.16	4.37	1.95	4.13	1.62	3.47
Canada	6.00	7.76	5.70	7.45	4.87	5.82
United States	4.49	5.19	9.09	10.87	6.01	7.31
Australia	18.60	20.21	9.76	12.14	13.50	14.38
Other Countries	7.47	9.01	6.21	10.69	8.07	9.94
Average Conventional	4.17	6.24	4.60	7.24	3.92	5.88
Synthetic Crude Oil						
Syncrude	21.96	22.18	18.10	18.21	19.43	20.29
Average Oil and Gas	5.19	7.56	5.42	8.26	4.88	7.10

Note:

[1] Operating costs per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2003 vs 2002 – Lower oil and gas operating costs increased net income by $23 million

Conventional unit operating costs decreased with the addition of low-cost production from Aspen in the Gulf of Mexico and the strengthening of the Canadian dollar relative to the US dollar. Increased workover and maintenance activity in Yemen and higher water handling costs in Canada partially offset this decrease.

Low-cost Aspen production reduced US operating costs by 50% and lowered our corporate average unit operating costs by approximately $0.40 per boe. Aspen production costs are about $1.05 per boe, $3.12 per boe lower than our corporate average for conventional production as most of the costs in our deep-water are capital related. Gunnison will produce at similar attractive operating costs.

The strengthening Canadian dollar decreased US-dollar denominated operating costs, lowering our corporate average unit operating costs by approximately $0.25 per boe. Higher repairs, increased maintenance and workover activity resulted in a US$0.40 per barrel increase in Yemen operating costs. We expect ongoing maintenance and workover activities at Masila to keep operating costs around US$1.70 per barrel. As well, unit operating costs offshore Australia and Nigeria increased as fixed costs were spread over declining production volumes.

Syncrude operating costs increased 21% due to higher natural gas input costs and increased turnaround and maintenance activity in 2003. Lower volumes also increased unit operating costs as more than 95% of the operating costs are fixed.

2002 vs 2001 - Higher oil and gas operating costs reduced net income by $58 million

Conventional operating costs increased $0.68 per equivalent barrel due to industry cost pressures in Canada, increased workover and repair activity on the shelf in the Gulf of Mexico and increased water-handling and waterflood costs in Yemen. As well, weather-related shut-ins and storm damage in the Gulf of Mexico and one time flood-related costs in Yemen contributed to the increase. In Australia, per-unit operating costs decreased significantly as fixed costs were spread over more barrels.

Depreciation, Depletion and Amortization (DD&A)

(Cdn$/boe)	2003		2002		2001	
	Before Royalties [2]	After Royalties	Before Royalties [2]	After Royalties	Before Royalties [2]	After Royalties
Conventional Oil and Gas						
Yemen	3.96	8.03	3.47	7.34	2.56	5.48
Canada [1]	9.10	11.76	8.22	10.72	7.14	8.53
United States	10.80	12.47	12.74	15.38	10.59	12.85
Australia	13.31	14.46	10.45	12.99	16.61	17.69
Other Countries	17.09	22.47	13.22	22.90	15.11	18.62
Average Conventional	7.37	11.04	6.84	10.81	5.97	8.98
Synthetic Crude Oil						
Syncrude	2.50	2.53	2.13	2.17	2.03	2.13
Average Oil and Gas	7.09	10.33	6.55	10.01	5.73	8.40

Notes:

[1] DD&A per boe excludes the impairment charge described in Note 4 of the Consolidated Financial Statements.

[2] DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2003 vs 2002 – Higher oil and gas DD&A reduced net income by $327 million

Conventional depletion rates increased with higher 2002 finding and development costs and our changing production mix, as more capital-intensive properties like Aspen contribute growing volumes. These properties, however, deliver higher-margin returns making them a valuable part of our portfolio. We also experienced higher depletion rates offshore Nigeria and Australia, as we prepare to abandon these fields in 2004.

The strengthening Canadian dollar offset these increases as our depletion from International and the US is denominated in US dollars. This lowered our corporate average rate by approximately $0.48 per boe.

Our DD&A expense for 2003 includes an impairment charge of $269 million ($175 million after-tax) largely attributable to reserve revisions to Canadian heavy oil properties. These reserve revisions were the result of changes to late field-life assumptions with respect to estimated future operating costs, changes to proved undeveloped reserves based on drilling results and geological mapping and reassessments of future estimated production profiles.

2002 vs 2001 – Higher oil and gas DD&A reduced net income by $80 million

Conventional depletion rates increased with higher 2001 finding and development costs in Canada, Yemen and the Gulf of Mexico and our changing production mix. A decrease in rates in Australia, resulting from successful infill drilling, partially offset these increases.

Exploration Expense

(Cdn$ millions)	2003	2002	2001
Seismic	62	75	77
Unsuccessful Drilling	70	61	133
Other	68	45	50
Total Exploration Expense	200	181	260
Total Exploration Capital	329	259	411
Exploration Expense as a % of Exploration Capital (%)	61	70	63

2003 vs 2002 - Higher exploration expense reduced net income $19 million

Exploration expense grew consistent with an increase in our 2003 exploration capital spending. Overall, our exploration program delivered excellent results from the Gulf of Mexico, OPL-222 offshore Nigeria and Block 51 in Yemen.

Dry hole and seismic costs in the Gulf of Mexico accounted for over 40% of our exploration expense. Exploration in the Gulf yielded some promising results at Shiloh. At Shiloh, we found hydrocarbons but not commercial quantities, so the well costs were written off. We still plan to actively pursue this prospect, have acquired additional acreage in the area and hope to prove-up commercial quantities in the region. We were unsuccessful at Santa Rosa but continue to pursue opportunities in the area.

Dry hole costs also included three wells in the Alberta foothills of Canada, the Andino-1 well in Colombia, the Escargot well offshore Brazil and the HEK well in Yemen on Block 51. In addition, we acquired seismic over a number of prospects.

2002 vs 2001 – Lower exploration expense added $79 million to net income

Exploration expense was lower in 2002 as we spent less on exploration capital, focusing our efforts on developing earlier exploration successes. Unsuccessful exploration wells included Block 59 in Yemen, Fusa in Colombia, Block BC-20 offshore Brazil and Fergana in the Gulf of Mexico.

OIL AND GAS MARKETING

(Cdn$ millions)	2003	2002	2001
Revenue	568	496	438
Transportation	(398)	(423)	(342)
Other	(1)	-	-
Net Revenue	169	73	96
Marketing contribution to Income from Continuing Operations before Income Tax	111	35	59
Physical Sales Volumes (excluding intra-segment transactions)			
Crude Oil (mboe/d)	479	412	400
Natural Gas (mmcf/d)	3,301	2,865	2,499
Value-at-Risk			
Year-end	21	19	19
High	31	28	24
Low	14	12	6
Average	20	17	13

2003 vs 2002 – Record net marketing revenue increased net income by $96 million
Marketing delivered record financial results growing their cash flow by 132% over 2002. This achievement was driven primarily by exceptional results from our gas marketing and trading group, supplemented by steady profits from our crude oil trading and marketing group.

Our natural gas group successfully positioned themselves to benefit from price differences between western Canada and eastern North America, and between summer and winter months. We also added transportation and storage capacity to our contract base. Added transportation capacity allowed us to take advantage of price differences between receipt and delivery points while added storage allowed us to take advantage of varying seasonal demand in the summer and winter months.

The continued exit of competitors from the market in 2003 enabled us to acquire contracts on favourable terms, including storage and transportation contracts and natural gas contracts.

We also successfully mitigated earlier volatility related to our storage positions by implementing a hedge accounting strategy. Until October 25, 2002, mark-to-market gains on our storage positions were included in net income. New accounting rules required us to exclude these gains from our results in 2003 until the inventory was sold despite having futures contracts in place that locked-in the profit on our stored volumes. At the beginning of the third quarter, we designated certain futures contracts as accounting hedges of the future sale of our stored volumes. As a result, recognition of the mark-to-market gain or loss on the futures contracts is deferred until the inventory is sold. See Note 5 to the Consolidated Financial Statements for further details.

2002 vs 2001 – Lower net marketing revenue reduced net income by $23 million
Marketing delivered solid results in 2002 despite having fewer opportunities. Less price volatility in 2002 resulted in smaller margins. This was offset somewhat by an increase in our marketed volumes, as there were fewer competitors in the market.

Composition of Net Marketing Revenue

(Cdn$ millions)	2003	2002
Derivative Energy Contracts	148	58
Non-Derivative Energy Contracts	21	15
	169	73

Derivative Energy Contracts
Our marketing operation engages in crude oil and natural gas marketing activities to enhance prices from the sale of our own production, and for energy marketing and trading. We enter into contracts to purchase and sell crude oil and natural gas. These contracts expose us to commodity price risk between the time contracted volumes are purchased and sold. We actively manage this risk by using physical purchases and sales, energy-related futures, forwards, swaps and options, and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. However, net open positions may exist, or we may establish them to take advantage of market conditions.

Consistent with our management practices, we account for all derivative energy contracts that are not designated as a hedge using mark-to-market accounting, and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is recorded as accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

We value derivative energy trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.

Fair Value of Derivative Energy Contracts

At December 31, 2003, the fair value of our derivative energy contracts not designated as hedges totalled $106 million (2002 - $3 million). The following table shows the valuation methods underlying these contracts together with details of contract maturity:

(Cdn$ millions)	Maturity				
	< 1 year	1-3 years	4-5 years	> 5 years	Total
Prices					
Actively Quoted Markets	(9)	1	-	-	(8)
From Other External Sources	77	30	9	(2)	114
Based on Models and Other Valuation Methods	-	-	-	-	-
Total	68	31	9	(2)	106

More than 64% of the unrealized gain is related to contracts that will settle in 2004. Contract maturities vary from a single day up to six years. Those maturing beyond one year are primarily from natural gas related positions. The relatively short maturity position of our contracts lowers our portfolio risk.

At December 31, 2003, the unrecognized losses on our derivative energy contracts accounted for as hedges of the future sale of our inventory totalled $11 million. The following table shows the valuation methods underlying these contracts together with details of contract maturity:

(Cdn$ millions)	Maturity				
	< 1 year	1-3 years	4-5 years	> 5 years	Total
Price					
Actively Quoted Markets	(11)	-	-	-	(11)
From Other External Sources	-	-	-	-	-
Based on Models and Other Valuation Models	-	-	-	-	-
Total	(11)	-	-	-	(11)

Our accounting policy does not permit us to record income on transportation and storage contracts using option valuation methods.

Changes in Fair Value of Derivative Energy Contracts

(Cdn$ millions)	Contracts Outstanding at Beginning of Year	Contracts Entered into and Closed During Year	Contracts Entered into During Year and Outstanding at End of Year	Total
Fair Value at December 31, 2002	3	-	-	3
Change in Fair Value of Contracts	6	53	89	148
Net Losses (Gains) on Contracts Closed	2	(53)	-	(51)
Derivative Energy Contracts Acquired	-	-	6	6
Changes in Valuation Techniques and Assumptions [1]	-	-	-	-
Fair Value at December 31, 2003	11	-	95	106
Unrecognized Losses on Hedges of Future Sale of Inventory at December 31, 2003	-	-	(11)	(11)
Total Outstanding at December 31, 2003	11	-	84	95

Note:

[1] Our valuation methodology has been applied consistently year over year.

Total Carrying Value of Derivative Energy Contracts

(Cdn$ millions)	2003	2002
Current Assets	102	42
Non Current Assets	63	14
Total Derivative Energy Contract Assets	165	56
Current Liabilities	34	46
Non Current Liabilities	25	7
Total Derivative Energy Contract Liabilities	59	53
Total Derivative Energy Contract Net Assets [1]	106	3

Note:
[1] Does not include effective hedges. We recognize gains and losses on effective hedges in the same period as the hedged item.

Unrecognized losses on forward contracts for the future sale of oil and gas production are disclosed in Note 5 of the Consolidated Financial Statements.

Non-derivative Energy Contracts

We enter into fee for service contracts related to transportation and storage of third party oil and gas. We also earn income from our power generation facility. We earned $21 million from our non-derivative energy activities in 2003 (2002 – $15 million).

CHEMICALS

(Cdn$ millions)	2003	2002	2001
Net Sales	375	367	373
Sales Volumes (thousand short tons)			
Sodium chlorate	478	454	457
Chlor-alkali	396	375	365
Operating Profit [1]	95	100	99
Operating Margin (%)	25	27	27
Chemicals contribution to Income from Continuing Operations before Income Taxes	28	27	47
Capacity Utilization (%)	95	85	89

Note:
[1] Total revenues less operating costs, transportation and other.

2003 vs 2002 – Lower chemicals operating profit reduced net income by $5 million

Many of the challenges we successfully managed in 2002 were replaced with new challenges in 2003. Strong North American demand for chlor-alkali and sodium chlorate helped boost sales volumes and prices in 2003. In North America, we manufacture our products in Canada. Most of our sales, however, are into US markets. As the Canadian dollar strengthened, our US-dollar denominated revenues declined, lowering our operating profit by $13 million.

Higher natural gas prices in North America put pressure on electricity costs. To deal with these cost pressures, we idled our Taft plant, our highest electricity cost facility, and relocated the assets to Brandon. Our cost savings from idling the plant were offset by product we purchased from other suppliers to satisfy southeastern US customers. Once the assets are installed at Brandon, we expect the savings to flow to our bottom line. The installation of the Taft assets at Brandon should be completed in 2004 eliminating our need for purchased product.

2002 vs 2001 – Chemicals operating profit adds $1 million to net income

We faced many challenges in 2002. Slow economic recovery in North America placed downward pressure on sodium chlorate volumes and eroded market prices. Also, increasing energy costs in Louisiana put pressure on our Taft plant.

During 2002, margins remained strong due to lower overall energy costs and the shifting of production from higher-cost to lower-cost facilities following the expansion of our Brandon and Brazil facilities. The expansion of these plants increased our depreciation.

CORPORATE EXPENSES

General and Administrative

(Cdn$ millions)	2003	2002	2001
General and Administrative Expenses	190	152	136

2003 vs 2002 – Higher costs and lower recoveries reduced net income by $38 million
Approximately 75% of the G&A increase relates to higher variable compensation:

- Record 2003 results increased bonus compensation by $16 million; and
- Strong stock prices at year-end increased the value of our employee stock appreciation rights and related expense by $13 million.

The continued expansion of our marketing group also increased our staffing costs in 2003.

2002 vs 2001 – Higher costs reduced net income by $16 million
Approximately 70% of the increase was due to higher staffing levels associated with our record capital investment program and growth in our marketing operations. The remainder resulted from increased pension expense due to poor equity market performance, higher building lease costs and incremental expenses associated with our stock appreciation rights plan.

Interest

(Cdn$ millions)	2003	2002	2001
Interest	148	140	112
Less: Capitalized Interest	43	31	-
Net Interest Expense	105	109	112
Effective Rate (%)	7.2	7.1	7.6

2003 vs 2002 – Lower interest expense increased net income by $4 million
Total interest costs increased $20 million due to:

- Full-year impact of our 30-year notes issued in March 2002, and;
- US$960 million issuance of new fixed-rate debt in November 2003.

This increase was offset by the strengthening Canadian dollar, which lowered our US-dollar denominated interest expense by $10 million.

Net interest expense decreased as capitalized interest related to major development projects costs continued to grow. Capitalized interest is expected to increase in 2004 as we proceed with major development projects at Long Lake and Syncrude.

2002 vs 2001 – Lower interest expense added $3 million to net income
Higher borrowing rate on our new 30-year notes increased interest costs by $28 million. We continued to capitalize interest on our major development projects resulting in lower net interest expense.

Income Taxes

(Cdn$ millions)	2003	2002	2001
Current	210	223	216
Future	(40)	(12)	67
	170	211	283
Effective Rate (%)	22	34	40

2003 vs 2002 – Effective tax rate declines from 34% to 22%
The 2003 effective tax rate fell primarily due to a reduction in tax rates for Canadian resource activities that resulted in a recovery of future income taxes of $76 million during the second quarter. The effective tax rate for 2004 is expected to be 33%.

The majority of our 2003 current income taxes were paid in Yemen. Current taxes include cash taxes in Yemen of $201 million (2002 - $207 million; 2001 - $191 million). During 2003 and 2002, federal and provincial capital taxes were payable in Canada. In 2003, current income taxes also include alternative minimum tax in the United States.

2002 vs 2001 – Effective tax rate declines from 40% to 34%
Rate decreased due to:

- lower federal and provincial statutory tax rates for Canadian non-oil and gas operations;
- higher portions of income coming from international operations where rates are lower; and
- non-taxable capital gain on the sale of our Moose Jaw operations.

Gain or Loss on Disposition of Assets

There was no gain or loss on the 2003 sale of our southeast Saskatchewan properties as described in Note 9 to the Consolidated Financial Statements. The net loss in 2002 includes a gain of $13 million on the sale of our asphalt operation in Moose Jaw, Saskatchewan and a loss of $21 million on the sale of a non-operated property by our Canadian oil and gas business segment.

Other Income

(Cdn$ millions)	2003	2002	2001
Foreign Exchange Gain (Loss)	6	(3)	-
Business Interruption Insurance Proceeds	12	-	-
Interest Income	9	7	17
Other	15	4	20
	42	8	37

The business interruption insurance proceeds received in 2003 relate to damage sustained in the Gulf of Mexico during tropical storm Isidore and hurricane Lili in the third and fourth quarters of 2002.

OUTLOOK FOR 2004

Our largest ever-capital program of $1.8 billion will focus on advancing our major development programs and high-quality exploration in four key basins. Our solid capital structure and surplus liquidity will support this program. In 2004, we plan to invest almost $1.7 billion in oil and gas with:

- 35% in core assets to maintain existing production levels;
- 45% in new growth development projects, and;
- 20% in new growth exploration projects.

Details of our 2004 capital investment program are included in the Capital Investment section in the MD&A. This program is consistent with our strategy to grow reserves and production primarily through the drill bit.

Daily Production

Approximately 45% of our cash flow from core assets will be reinvested in those assets to deliver production between 255,000 and 275,000 boe per day in 2004. The remaining 55% of cash flow will be invested in new growth projects.

	2004 Estimated Production	
(mboe/d)	Before Royalties	After Royalties
Gulf of Mexico [1]	60 - 65	55 - 57
Yemen, Masila	110 - 118	58 - 62
Canada Conventional [2]	57 - 65	46 - 53
Syncrude	16 - 18	16 - 17
Other International	7 - 9	6 - 8
Total	255 - 275	180 - 195

Notes:

[1] US natural gas production is estimated to comprise 45% of total US equivalent production in 2004.

[2] Canadian natural gas production is estimated to comprise 33% of total Canadian equivalent production in 2004.

Our net production growth will be modest in 2004, as over half our cash flow is invested in major growth projects coming on-stream in 2005 and beyond. Many of these projects have low or no royalties, lower costs and ultimately higher returns than our current producing assets. This changing production mix will improve profitability, even if oil prices trend lower.

We expect to generate around $1.3 billion in cash flow from operations in 2004 assuming the following:

WTI (US$/bbl)	25.00
NYMEX natural gas (US$/mmbtu)	4.25
US to Canadian dollar exchange rate	0.75

Changes in actual commodity prices and exchange rates will impact our annual cash flow from operations as follows:

(Cdn$ millions)	
WTI – US $1 change	53
NYMEX natural gas – US $0.50 change	60
Exchange rate – $0.01 change	21

In a price-neutral environment, cash flow from operations would grow by approximately 10% over 2003 and we would see 11% growth in our corporate cash netback.

In addition to strong cash flow from our oil & gas operations, we expect solid performance from our chemicals and marketing businesses in 2004. Our chemicals operations anticipate improved cash flow from growing production and lower unit costs as we continue to consolidate production at our low-cost facility in Brandon. Our marketing group also anticipates another profitable year as they continue to increase their presence in core markets in the US midwest and eastern Canada.

LIQUIDITY

Sources and Uses of Cash

Our business strategy is focused on value-based growth through full-cycle exploration and development, supplemented by strategic acquisitions when appropriate. We rely on operating cash flows to fund capital requirements and provide liquidity. We build our opportunity portfolio to provide a balance of short-term, mid-term, and longer-term growth. This enables us to generate ongoing sustainable operating cash flows as shown below:

(Cdn$ millions)	2003	2002	2001	2000	1999
Cash Flow from Operations	1,859	1,383	1,423	1,569	780
Capital Expenditures	(1,494)	(1,625)	(1,404)	(915)	(612)
	365	(242)	19	654	168
WTI (US$/bbl)	31.04	26.09	25.97	30.21	19.24
NYMEX natural gas (US$/mmbtu)	5.60	3.37	4.00	4.31	2.31

The capital investment in our oil and gas operations is primarily funded by our cash flow from operations. Although this spending is mostly discretionary, we rely on prudent capital investment to generate future operating cash flows. Given the long cycle time of some of our development projects, particularly internationally, and the volatility of commodity prices, it is not unusual, in any given year for capital expenditures to exceed our cash flow.

In 1998 and 1999, commodity prices were low and we reduced our capital investment. In 2000, commodity prices improved, allowing us to generate sufficient cash flow from operations to buy back 20 million common shares. In 2001 and 2002, we began to invest significantly in two deep-water Gulf of Mexico prospects (Aspen and Gunnison), our Syncrude expansion and our Long Lake project. In 2003, Aspen contributed significantly to our cash flow from operations and in 2004, we expect additional significant contributions from Gunnison. We anticipate cash flows from the Syncrude expansion and Long Lake to commence in 2006 and 2007, respectively.

Given the cyclical nature of the upstream oil and gas business, we manage our capital structure so that we are well positioned from a liquidity perspective throughout both positive and negative commodity price cycles. Our capital structure is characterized by a modest level of absolute debt, a long term to maturity and undrawn committed credit facilities.

Capital Structure

(Cdn$ millions)	2003	2002
Bank Debt	-	-
Senior Public Debt	2,776	1,844
	2,776	1,844
Less: Cash	1,087	59
Less: Non-Cash Working Capital [1]	312	10
Net Debt [2]	1,377	1,775
Preferred and Subordinated Securities	364	724
Net Debt, including Preferred and Subordinated Securities	1,741	2,499
Shareholders' Equity [3,4]	2,418	2,348

Notes:

1 Excludes current portion of long-term debt.

2 Long-term debt less net working capital.

3 Included in shareholders' equity are preferred and subordinated securities of $364 million (2002 - $724 million). Under US generally accepted accounting principles, these are considered long-term debt.

4 At January 31, 2004, there were 126,738,410 common shares and US$460 million of unsecured subordinated securities outstanding. These subordinated securities may be redeemed by the issuance of common shares at our option after November 8, 2008. The number of shares to be issued will depend upon the common share price on the redemption date.

We significantly enhanced our capital structure in 2003:

Shareholders' equity	Continued to strengthen with record net income in 2003.
US$500 million of 5.05% debt	Issued in November 2003 and maturing in 10 years. Proceeds were used to repay US$225 million of long term debt early in February 2004, and to fund a portion of our 2004 capital investment program.
US$460 million of 7.35% subordinated debentures	Issued in November 2003 and maturing in 40 years. Proceeds were partially used to redeem our 2047 preferred securities in December 2003 and our 2048 preferred securities in early February 2004.
Committed bank facilities of $1,656 million	All undrawn at year-end with 75% of the facilities available to the end of 2008 and the remainder to the end of 2007.
US$1 billion universal debt shelf prospectus	Available until October 2005 in the US and Canada.
Favourable debt maturities	Pre-financed our 2004 debt maturity. Our remaining maturities over the next five years are minimal. The average term to maturity of our debt is 20 years.

Change in Working Capital

(Cdn$ millions)	2003	2002	Increase/ (Decrease)
Cash and Short-Term Investments	1,087	59	1,028
Accounts Receivable	1,423	988	435
Inventories and Supplies	270	256	14
Accounts Payable and Accrued Liabilities	(1,404)	(1,194)	(210)
Other	23	(40)	63
	1,399	69	1,330

Cash and short-term investments increased with our fourth quarter financing activities. We received proceeds of US$960 million when we issued US$500 million of notes and US$460 million of subordinated debentures in November 2003. We used US$701 million of this cash to redeem US$259 million of preferred securities in December 2003, US$217 million of preferred securities in early February 2004 and US$225 million of senior notes in early February 2004. Accounts receivable increased in part because there was no sale of receivables at the end of 2003 compared to the sale of $178 million at the end of 2002. The remainder of the increase was due to higher commodity prices and growth in our marketing business offset by the strengthening of the Canadian dollar relative to the US dollar.

The increase in other was related to the prepayment of natural gas storage inventory in December.

Net Debt

Our net debt levels are directly related to our operating cash flows and our capital expenditure activities. During the year, we successfully reduced net debt, including preferred and subordinated securities, by $758 million:

(Cdn$ millions)	2003	2002
Capital Expenditures	1,494	1,625
Cash Flow from Operations	(1,859)	(1,383)
	(365)	242
Dividends on Preferred Securities and Common Shares	104	109
Foreign Exchange Translation of US-dollar Debt and Cash	(281)	-
Proceeds on Disposition of Assets	(293)	(49)
Issue of Common Shares	73	51
Other	4	(38)
Increase (Decrease) in Net Debt, including Preferred and Subordinated Securities	(758)	315

The reduction in net debt has a positive impact on our leverage metrics:

	2003	2002	2001
Net Debt, including Preferred Securities and Subordinated Securities, to Cash Flow [1] (times)	1.0	1.9	1.6
Interest Coverage [2] (times)	13.3	10.7	13.7
Fixed Charge Coverage [3] (times)	9.5	7.2	8.4

Notes:
1 Cash flow comprises cash flow from operations after dividends on Preferred Securities.
2 Cash flow from operations before interest expense divided by total interest.
3 Cash flow from operations before interest expense divided by total interest plus dividends on Preferred Securities.

Our net debt and preferred securities are equal to 1.0 times our 2003 cash flow from operations after dividends on preferred securities. This, together with our coverage ratios, provides us with sufficient financial flexibility and liquidity to pursue our business strategy.

Future Liquidity

Our future liquidity is primarily dependent on cash flows generated from our operations, our capital investment programs and the flexibility of our capital structure. Assuming WTI of US$25 per bbl for 2004, we expect our 2004 capital investment program and dividend requirements to exceed our cash flow from operations by almost $550 million.

Our cash flow from operations is sensitive to changes in commodity prices and exchange rates. For 2004, we expect cash flow from operations of $1.3 billion, assuming the following:

WTI (US$/bbl)	25.00
NYMEX natural gas (US$/mmbtu)	4.25
US to Canadian dollar exchange rate	0.75

Changes in commodity prices and exchange rates will impact our cash flow from operations and our borrowing requirements. The impact of a variance, in any one of the above assumptions, on our cash flow from operations is described in the Outlook for 2004 section in the MD&A.

If we change our capital investment program, we may draw more or less on our cash balances and our available facilities. We are currently entering a 4-year period of investing in major development projects as we move forward with our projects at Long Lake in Canada and on Block 51 in Yemen.

Given our stable operating cash flows, strong cash position and undrawn committed credit facilities, we do not anticipate any problems in funding our capital programs, dividend requirements, and debt repayments or in meeting the obligations that arise from our day-to-day operations. In 2003, we declared common share dividends of $0.325 per common share (2002 - $0.30, 2001 - $0.30). We expect to declare common share dividends of $0.40 per common share in 2004.

Contractual Obligations, Commitments and Guarantees

We have assumed various contractual obligations and commitments in the normal course of our operations and financing activities. These obligations and commitments have been considered when assessing our cash requirements in the above discussion of future liquidity.

(Cdn$ millions)			Payments [1]		
	Total	<1 year	1-3 years	4-5 years	>5 years
Long-Term Debt [1]	2,776	291	98	275	2,112
Preferred and Subordinated Securities [1]	364	331	-	-	33
Operating Leases [2]	217	33	58	35	91
Transportation and Storage Commitments [2]	580	212	172	85	111
Work Commitments	81	64	17	-	-
Dismantlement and Site Restoration	514	18	28	32	436
Other	1	1	-	-	-
Total	4,533	950	373	427	2,783

Notes:

[1] Payment obligations are not discounted and do not include related interest, accretion or dividends. At December 31, 2003, we had cash and short-term investments of $1,087 million.

[2] Payments for operating leases and transportation commitments are deducted from our cash flow from operations.

Contractual obligations include both financial and non-financial obligations. Financial obligations represent known future cash payments that we are required to make under existing contractual arrangements, such as debt and lease arrangements. Non-financial obligations represent contractual obligations to perform specified activities such as work commitments. Commercial commitments represent contingent obligations that become payable only if certain pre-defined events occur.

- Long-term debt amounts are included in our December 31, 2003 Consolidated Balance Sheet. The amount due in 2004 has been included in our current liabilities. Under US GAAP, $331 million of preferred securities and $33 million of subordinated securities would be included in long-term debt.
- Operating leases include leases for office space, rail cars, vehicles, the lease of the FPSO in Australia, and our processing agreement with Shell that allows our Aspen production to flow through Shell's processing facilities at the Bullwinkle platform. The terms of the processing agreement give Shell an annual option to take payment in cash or in kind. For 2004, Shell has elected to take payment in kind so the 2004 obligation has been excluded from this table.
- Our marketing operation manages various natural gas transportation and storage commitments on behalf of our Canadian oil and gas business and a number of third-party customers.

- Work commitments include non-discretionary capital spending related to drilling and seismic commitments in our international operations and development commitments at Syncrude. The remainder of our 2004 capital investment is discretionary.
- We have $514 million of future dismantlement and site restoration obligations. As of December 31, 2003, $197 million of these obligations have been provided for on our balance sheet (including $18 million of current liabilities). The timing of any payments is difficult to determine with certainty and the table has been prepared using our best estimates.
- We have unfunded obligations under our defined benefit pension and post retirement benefit plans of $84 million. Our unfunded obligation is $43 million and our share of Syncrude's unfunded obligation is $41 million. Our $43 million obligation includes $29 million that is unfunded as a result of statutory limitations. These obligations are backed by letters of credit. During 2003, we contributed $16 million to our defined benefit pension plan. Post year-end positive equity markets have helped restore our defined benefit plan to a fully funded position.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operations and our capital expenditures for 2004.

From time to time we enter into contracts that require us to indemnify parties against possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated. Because the obligation is stated, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. Our Risk Management Committee actively monitors our exposure to the above risks and obtains insurance coverage to satisfy potential or future claims as necessary. We believe these matters would not have a material adverse effect on our liquidity, financial condition or results.

Credit Ratings

Currently, our senior debt is rated BBB by Standard & Poor's, Baa2 by Moody's Investor Service, Inc. and BBB by Dominion Bond Rating Service. In addition, all rating agencies currently rate our outlook as stable. Our strong financial results, ample liquidity and financial flexibility continue to support our credit rating.

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our marketing division enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require posting collateral (in the form of either cash or a letter of credit) if a buyer's credit rating drops below investment grade, indicating their creditworthiness has deteriorated. Based on the contracts in place and commodity prices at December 31, 2003, we would be required to post collateral of $321 million if we were downgraded to non-investment grade. This obligation is reflected in our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Our committed undrawn credit facilities of $1.7 billion adequately cover any potential collateral requirements. Just as we may be required to post collateral in the event of a downgrade below investment grade, we have similar provisions in many of our customer contracts that allow us to demand certain customers post collateral with us if they are downgraded to non-investment grade.

Off-Balance Sheet Arrangements

None.

Contingencies

See Note 10 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference for a discussion of our contingencies.

BUSINESS RISK MANAGEMENT

The oil and gas industry is highly competitive, particularly in the following areas:

- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include major integrated oil and gas companies and numerous other independent oil and gas companies.

The pulp and paper chemicals market is also highly competitive. Key success factors are:

- price and product quality; and
- logistics and reliability of supply.

We are one of the largest producers of sodium chlorate in North America and have continent-wide supply capability.

Operational Risk

Acquiring, developing and exploring for oil and natural gas involves many risks. These include:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- blow-outs, well bore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids;
- adverse weather conditions; and
- environmental risks.

Although we maintain insurance according to customary industry practice, we cannot fully insure against all of these risks. Losses resulting from the occurrence of these risks may have a material adverse impact.

Our future crude oil and natural gas reserves and production, and therefore our operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions, our existing reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. If cash flow from operations is insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves could be impaired.

Uncertainty of Reserve Estimates

Oil and gas reserves are integral to assessing our expected future financial performance, preparing our financial statements and making investment decisions. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. The reserves included in this Form 10-K represent estimates only.

To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepared the estimates. However, actual results could vary considerably, which could cause material variances in:

- estimated quantities of proved oil and natural gas reserves in aggregate and for any particular group of properties;
- reserve classification based on risk of recovery;
- future net revenues, including production, revenues, taxes, and development and operating expenditures; and
- financial results including the annual rate of depletion and recognition of property impairments.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements.

Reserve estimates for each property are prepared at least annually by the property's reservoir engineer. They are reviewed by engineers familiar with the property and by divisional management. Senior management, including our CEO, CFO and Board-appointed internal qualified reserves evaluator, meet with divisional reserves personnel to review the estimates and any changes from previous estimates.

The internal qualified reserves evaluator assesses whether our reserves estimates and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein, included in the Supplementary Financial Information, have been prepared in accordance with our reserve standards. His opinion stating that the reserves information has, in all material respects, been prepared according to our reserves standards is included in an exhibit to Form 10-K.

We also have at least 80% of our reserve estimates audited annually by independent qualified reserves consultants. Given that the reserves estimates are based on numerous assumptions and interpretations, differences in estimates prepared by us and an independent reserves consultant within 10% are considered immaterial. Differences greater than 10% are resolved.

The Board of Directors has established a Reserves Review Committee (Reserves Committee) to assist the Board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent, and each being familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, results and related disclosures. The Reserves Committee appoints and meets with each of the internal qualified reserves evaluator and independent reserves consultants independent of management to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

The Reserves Committee has reviewed Nexen's procedures for preparing the reserve estimates and related disclosures. It has reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result of this, the Reserves Committee is satisfied that the internally-generated reserves are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the Board has approved the reserves estimates and related disclosures in the Form 10-K.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information in the Form 10-K are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows will also be affected by factors such as actual production levels and timing, and changes in governmental regulation or taxation, and may differ materially from estimated cash flows. See the Critical Accounting Estimates section of this MD&A where we discuss the impact of changes in our reserve estimates.

Political Risk

We operate in numerous countries, some of which may be considered politically and economically unstable. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists. We conduct our business and financial affairs to protect against political, legal, regulatory and economic risks applicable to operations in the various countries where we operate. However, there can be no assurance that we will be successful in protecting ourselves from the impact of these risks.

Our Masila operations are important to Yemen, providing 50% of the country's oil production. We are a responsible member of the Yemeni community; we build relationships with its members and involve them in key decisions that impact their lives. We also ensure that they benefit from our presence in their country beyond the revenue they receive from the production we operate. Our strong relationship with the people and Government of Yemen has allowed us to operate there without interruptions for almost 14 years and we anticipate this continuing.

Our practices have enabled us to operate successfully, not only in Yemen, but also in other parts of the world. We have developed excellent practices to manage the risks successfully.

Environmental Risk

Environmental risks inherent in the oii and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the disposal or release of specified substances.

We manage our environmental risks through a comprehensive and sophisticated Safety, Environmental and Social Responsibility (SESR) Management System that meets or exceeds ISO14001 criteria and those of similar management systems. Overall guidance and direction is provided by the SESR Committee of the Board of Directors. In addition, senior management, including the CEO and CFO, regularly meets with SESR management to review and approve SESR policies and procedures, provide strategic direction, review performance and ensure that corrective action is taken when necessary. We develop and implement proactive and preventative measures designed to reduce or eliminate future environmental liabilities, we are prudent and responsible in our management of existing environmental liabilities, and we continuously seek opportunities for performance improvement. We also maintain an ongoing awareness of external trends, demands, commitments, events or uncertainties that may reasonably have a material effect on revenues from continuing operations. These actions provide assurance that we meet or exceed appropriate environmental standards worldwide.

- At December 31, 2003, $197 million has been provided in the Consolidated Financial Statements for future dismantlement and site restoration costs, currently estimated at $514 million for our oil and gas and chemicals facilities.
- During 2003, we recorded a provision for future dismantlement and site restoration costs of $38 million (2002 - $43 million; 2001 - $45 million).
- Actual site remediation expenditures for the year were $21 million (2002 - $20 million; 2001 - $24 million). We anticipate actual site remediation expenditures in 2004 to approximate 2003 levels.
- We perform periodic internal and external assessments of our operations and adjust our estimates and annual provision accordingly.
- During 2002, we conducted an external audit of our management system for safety, environment and social responsibility issues. In general, the review was very positive and the few minor recommendations for improvement are being implemented.
- During 2003, we commenced an external operational audit to confirm whether our management system for safety, environment and social responsibility issues is actually being followed. This work is continuing into 2004, but initial reports are very positive.

Climate Change

The Kyoto Protocol, an agreement to reduce the concentration of certain man-made gases (Green House Gases or GHG) that may be contributing to climate change, was signed by approximately 160 countries since 1997. Canada ratified the Kyoto Protocol in December 2002, but it will not come into effect until it is ratified by Russia. The Kyoto Protocol obliges the Annex 1 countries to meet national targets. Canada's target is an emission reduction of 6% below 1990 levels during the First Commitment period of 2008 to 2012. Economic modeling studies have shown that if emission reductions are met through domestic action in Annex I countries alone, there will be severe negative impacts to those countries' economies, and in particular those such as Canada whose economies are resource and energy intensive. The US government's decision to withdraw from the Kyoto Protocol has serious implications for Canada in the context of a continental or hemispheric energy market.

The Canadian government has addressed the uncertainty around ratification and implementation of the Kyoto Protocol by providing the oil and gas sector with limits on cost (a cap of $15 per tonne) and volume (a cap of 55 megatonnes for large industrial emitters) as well as its position on long-term high capital cost projects. However, the government has yet to enact national legislation that will detail the obligations of Canadian industry with respect to emission reduction and management, and it is uncertain at this time when those obligations will be determined. The financial markets have viewed these developments favourably and have issued various analyses in the aftermath of these announcements indicating that implementation of GHG-related legislation should not adversely affect the development of new energy projects such as the oilsands.

For years, Nexen has been assessing the impact of climate change developments on our various business interests. We have created a senior management committee (The Climate Change Steering Group) to: consider national and international developments; hear from leading experts with respect to science, business and risk issues; and, consider investment opportunities. As well, Nexen continues to work closely with the Canadian and Alberta governments to assess the impact of regulatory options and provide information on our business to assist governments in their policy deliberations. Nexen maintains a wide range of business contacts to ensure that a full slate of options is available to the corporation in order to meet the obligations that may be imposed by future legislation.

Nexen is a Gold level reporter in Canada's Voluntary Challenge and Registry (VCR); our 2002 VCR report includes the observation that we have voluntarily reduced our direct emissions by almost 2 million tons of CO_2 equivalent since we started reporting in 1996. As well, progress has been made toward reduction of our energy inputs per unit of production. In 2003, we initiated another gas gathering project in heavy oil. We are still assessing our 2003 performance and it will be reported to the VCR.

Nexen has looked to GHG emission reduction and to offset investments. In 1995, we started capturing, compressing and selling methane gas from our Canadian heavy oil operation instead of venting it to the atmosphere. As a Canadian-based international oil and gas exploration and production company, we have worked closely with the Canadian Clean Development Mechanism/Joint Implementation Office of the Department of Foreign Affairs and International Trade to ensure that Canadian companies get access to low cost/high quality carbon offset investments. Nexen has entered into discussions with the management of several GHG investment pools and continues to evaluate the opportunities associated with biological and geological sequestration of CO_2 and the capture of methane from landfills. We continue to investigate carbon-offset opportunities in each of our core countries in the belief that there may be synergies between our oil and gas activities and carbon investments. We continuously review the feasibility of new and ongoing projects with respect to current social, political and economic factors and will continue to take into account the policy and requirements with respect to GHG when conducting these reviews .

We are committed to the principles of full disclosure and will keep our stakeholders apprised of how these issues affect us. Since emission levels applicable to our business operations have not been determined and there are no reliable estimates of the costs of achieving those levels, premature disclosure would be speculative and any financial estimates would be based on arbitrary assumptions of emission levels; however, Canadian government assurances of cost and volume limits suggest that incremental risks and liabilities attributable to addressing climate change policies are manageable. Finally, any indirect risks and liabilities attributable to GHG are too remote and unquantifiable at this time.

MARKET RISK MANAGEMENT

We are exposed to normal market risks inherent in the oil and gas and chemicals business, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations to minimize our exposure, as described in Note 5 to the Consolidated Financial Statements, which is incorporated by reference here.

Sensitivities

(Cdn$ millions)	Cash Flow	Net Income
Estimated 2004 impact:		
Crude Oil - US$1.00/bbl change in WTI	53	41
Natural Gas - US$0.50/mcf change	60	38
Foreign Exchange - $0.01 change in US to Cdn Dollar	21	9

Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals.

To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices and North American supply and demand, and to a lesser extent local market conditions.

Non-Trading Activities

The majority of our production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

In March 2003, we sold WTI and NYMEX gas forward contracts for the next 12 months to lock-in part of the return on the remaining 40% interest acquired in the Aspen field. The forward contracts fix our oil and gas prices at the contract prices for the hedged volumes, less applicable price differentials as follows:

	Hedged Volumes	Term	Average Price (US$)
Fixed WTI Price	5,000 bbls/d	April 2003 – March 2004	28.50/bbl
Fixed NYMEX Price	12,000 mmbtu/d	April 2003 – March 2004	5.35/mmbtu

During 2002 and 2001, we purchased fixed-to-floating swaps to modify the terms of certain fixed-price natural gas contracts as we prefer to receive an index-based price for our natural gas. Under the terms of these contracts, we were required to deliver four million cubic feet per day of natural gas to counterparties at prices ranging from $3.06 to $6.08 per mcf. On settlement, we received or paid cash for the difference between the contract and floating rates on the affected volumes. These swaps expired in 2003.

Marketing and Trading Activities

Our marketing operation is involved in the marketing and trading of crude oil and natural gas, through the use of both physical and financial contracts (energy trading activities). These activities expose us to commodity price risk. Open positions exist where not all contracted purchases and sales have been matched, in order to take advantage of market movements. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk) and credit exposure. We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- stop loss limits; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss given a 95% confidence level that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR using the Variance-Covariance method based on historical commodity price volatility and correlation inputs. Our estimate is based upon the following key assumptions:

- changes in commodity prices are normally distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock occurred, the key assumptions underlying our VaR estimate could be violated and the potential loss could be greater than our estimate. There were no changes in the methodology we used to estimate VaR in 2003.

Stress testing complements our VaR estimate. It is used to ensure that we are not exposed to large losses, not captured by VaR, which might result from infrequent but extreme market conditions.

Our Board of Directors has approved formal risk management policies for our energy trading activities. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and review the results of energy trading activities regularly.

Foreign-Currency Rate Risk

A substantial portion of our operations are denominated in or referenced to US dollars. These activities include:

- prices received for sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses related to our oil and gas and chemicals operations outside Canada; and
- short-term and long-term borrowings.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Since the timing of cash inflows and outflows is not necessarily interrelated, particularly for capital expenditures, we maintain revolving US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our long-term US-dollar borrowings as a hedge against our US-dollar net investment in foreign operations.

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. Information regarding our foreign currency net investments, borrowings and related derivative instruments is provided in Note 5 to the Consolidated Financial Statements.

Interest Rate Risk

We are exposed to fluctuations in short-term interest rates from our floating-rate debt and, to a lesser extent, derivative instruments, as their market value is sensitive to interest rate fluctuations. We maintain a portion of our debt capacity in revolving, floating-rate bank facilities with the remainder issued in fixed-rate borrowings. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments as described in Note 5 to the Consolidated Financial Statements.

At December 31, 2003, we had no floating-rate debt outstanding (2002 - $nil; 2001 - $424 million).

Credit Risk

Credit risk is the risk of loss if customers or counterparties do not fulfill their contractual obligations. Most of our receivables are with customers in the energy industry requiring our products on an ongoing basis. These customers are subject to normal industry credit risk. This concentration of risk within the energy industry is mitigated through our broad domestic and international customer base. It is also possible that derivative instrument counterparties will not fulfill their contractual obligations. We take the following measures to reduce this risk:

- we assess the financial strength of our customer and counterparty base through a rigorous credit process;
- we limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- we routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the Board;
- we set credit limits based on counterparty credit ratings and internal models, which are based primarily on company and industry analysis;
- we review counterparty credit limits regularly; and
- we use standard agreements that allow for netting of positive and negative exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. At December 31, 2003:

- 90% of our counterparty exposures were investment grade; and
- only five customers individually made up greater than 5% of our exposure from energy trading activities. All were investment grade.

CRITICAL ACCOUNTING ESTIMATES

As an oil and gas producer, there are a number of critical estimates underlying the accounting policies we apply when preparing our Consolidated Financial Statements. These critical estimates are discussed below.

Oil and Gas Accounting – Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas properties. The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Our reserve estimates are based on current production forecasts, prices and economic conditions. See Business Risk Management for a complete discussion of our reserves estimation process.

Reserve estimates are critical to many of our accounting estimates, including:

- Determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2003, $70 million of our total $180 million spent on exploration drilling was expensed in the year. If none of our drilling had been successful, our net income would have decreased by $72 million after tax.
- Calculating our unit-of-production depletion and asset retirement obligation rates. Both proved and proved developed reserve[1] estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense and our provision for dismantlement and site restoration. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2003, oil and gas depletion, before impairment charges, and oil and gas dismantlement and site restoration costs of $636 million and $34 million, respectively, were recorded in depletion, depreciation and amortization expense. If our reserve estimates changed by 10%, our depletion, depreciation and amortization expense would have changed by approximately $50 million, after tax, assuming no other changes to our reserve profile.

[1] "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered "proved" if economic producability is supported by either actual production or a conclusive formation test. "Proved developed" oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operation methods.

- Assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

As circumstances change and additional data becomes available, our reserve estimates also change, possibly materially impacting net income. Estimates made by our engineers are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although we make every reasonable effort to ensure that our reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to our reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative. Reserves information is shown in the Supplementary Financial Information set out in Item 8 of this Form 10-K.

It would take a very significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in Liquidity.

Oil and Gas Accounting - Impairment

We evaluate our oil and gas properties for impairment if an adverse event or change occurs. Among other things, this might include falling oil and gas prices, a significant revision to our reserve estimates, changes in operating costs, or significant or adverse political changes. If one of these occurs, we estimate undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flows for a property are less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value.

We assessed our oil and gas properties for impairment following the 2003 revisions to our reserve estimates. As a result of this assessment, it was determined that certain Canadian oil and gas properties were impaired. These properties were written down to their fair value which resulted in an impairment charge of $175 million, after-tax. See Note 4 to the Consolidated Financial Statements for further information.

Our cash flow estimates for purposes of our impairment assessments require assumptions about two primary elements – future prices and reserves.

Our estimates of future prices require significant judgements about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility - over the last five years, prices for WTI and NYMEX gas have ranged from US$10/bbl to US$38/bbl and US$2/mmbtu to US$10/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. Our estimates of future cash flows generally assume our long-term price forecast and forecast operating costs. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in this estimate would impact all except our chemicals business.

If we decreased our long-term forecast for WTI crude oil prices by US$1.00-1.50/bbl, our initial assessment of impairment indicators would not change. Although oil and gas prices fluctuate a great deal in the short-term, they are typically stable over a longer-time horizon. This mitigates the potential for impairment.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment. We do, however, have confidence in our reserve estimates.

Any impairment charges would lower our net income.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, *Hedging Relationships* (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. The guideline is effective for fiscal years beginning on or after July 1, 2003. Adoption of AcG-13 is not expected to have a material impact on our financial position or results of operations as we are already in compliance with Financial Accounting Standards Board (FASB) Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

In September 2002, the CICA approved Section 3063, *Impairment of Long-Lived Assets* (S.3063). S.3063 establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. S.3063 is effective for fiscal years beginning on or after April 1, 2003. Adoption of S.3063 is not expected to have a material impact on our financial position or results of operations.

In December 2002, the CICA approved Section 3110, *Asset Retirement Obligations* (S.3110). S.3110 requires liability recognition for retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liabilities. This fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful life. The liabilities accrete until we expect to settle the retirement obligations. S.3110 is effective for fiscal years beginning on or after January 1, 2004. The impact on our consolidated balance sheet at January 1, 2004, will be as follows:

(Cdn$ millions)	Increase/(Decrease)
Property, Plant and Equipment	81
Asset Retirement Obligation	126
Future Income Tax Liability	(16)
Retained Earnings	(29)

In February 2003, the CICA issued Accounting Guideline 14, *Disclosure of Guarantees* (AcG-14). AcG-14 establishes the disclosures required for obligations we may have under certain guarantees that we have issued. The disclosure requirements are effective for interim and annual periods beginning on or after January 1, 2003. We adopted FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others*, the US equivalent of AcG-14 for the year ended December 31, 2002. We have disclosed our guarantees in Note 10. There were no material guarantees outstanding at December 31, 2003.

In November 2003, the CICA approved an amendment to Section 3860, *Financial Instruments – Disclosure and Presentation,* to clarify the difference between an equity and liability instrument. An equity instrument exists only when an instrument is settled in shares. This amendment is effective for fiscal years beginning on or after November 1, 2004. Once adopted, our preferred and subordinated securities would be reclassified from equity to long term debt, and the dividends paid would be classified as interest expense. Adoption of this amendment at December 31, 2003, would increase long term debt by $313 million, decrease preferred and subordinated securities by $364 million and increase the cumulative translation adjustment by $51 million.

The following standards or revisions issued by the CICA do not impact us:

- Section 1100, *General Accounting Principles* effective for years beginning on or after October 31, 2003.
- Section 1400, *General Standards of Financial Statement Presentation* effective for years beginning on or after October 31, 2003.
- Accounting Guideline 15, *Consolidation of Variable Interest Entities*, effective for annual and interim periods beginning on or after January 1, 2004.

US Pronouncements

The following standards issued by the FASB do not impact us:

- Statement No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities,* effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003.
- Interpretation No. 46, *Consolidation of Variable Interest Entities*, effective for financial statements issued after January 31, 2003.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Please refer to the Business and Marketing Risk Management sections of Item 7 for the required disclosures about Market Risk.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2 - Business and Properties* and *Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations*, are forward-looking statements.[1] Forward-looking statements are generally identifiable by terms such as *anticipate, believe, intend, plan*, *expect*, *estimate*, *budget, outlook* or other similar words.

These statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. These risks, uncertainties and other factors include:

- market prices for oil, natural gas and chemicals products;
- our ability to produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions that increase taxes, change environmental and other laws and regulations;
- renegotiations of contracts; and
- political uncertainty, including actions by terrorists, insurgent or other groups or armed other conflict, including conflict between states.

The above items and their possible impact are discussed more fully in the section, titled *Business Risk Management* and *Market Risk Management* in Item 7.

The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and management's future course of action depends upon our assessment of all information available at that time. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues from our operations in Yemen;
- future capital expenditures and their allocation to exploration and development activities;
- future sources of funding for our capital program;
- future debt levels;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- future expenditures and future allowances relating to environmental matters; and
- dates by which certain areas will be developed or will come on-stream.

We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. We undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

[1] Within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended.

Special Note to Canadian Investors

Nexen is a US Securities and Exchange Commission (SEC) registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures generally follow SEC requirements.

In 2003, certain Canadian regulatory authorities adopted *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribe that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. We have been granted the following exemptions permitting us to:

- substitute our SEC disclosures for much of the annual disclosure required by NI 51-101;
- prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook (COGE Handbook) modified to reflect SEC requirements;
- dispense with the requirement to have our reserves estimates and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein, included in the Supplementary Financial Information, evaluated or audited by independent qualified reserves evaluators; and
- not disclose certain prescribed information pertaining to prospects if such disclosures would result in the contravention of a legal obligation, would likely be detrimental to our competitive interests or the information does not exist.

As a result of these exemptions, Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved producing reserves by country only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not require separate disclosure of proved undeveloped reserves or related future development costs whereas NI 51-101 requires disclosure of more information regarding proved undeveloped reserves, related development plans and future development costs;
- the SEC does not prescribe standards for calculating finding and development costs per boe of proved reserves additions whereas NI 51-101 requires that finding and development costs per boe be calculated by dividing the aggregate of exploration and development costs incurred in the current year and the change in estimated future development costs relating to proved reserves by the additions to proved reserves in the current year. However, this will generally not reflect full cycle finding and development costs related to reserve additions for the year. Instead, we have calculated finding and development costs by dividing exploration and development costs incurred in the current year by the additions to proved reserves in the current year (F&D); and
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports.

The foregoing is a general description of the principal differences only.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boes) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Item 8. Financial Statements and Supplementary Financial Information

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REPORT OF MANAGEMENT

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and integrity of all the information contained in the accompanying consolidated financial statements. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US. We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly.

Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all the required regulatory disclosures.

To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that the existing internal controls over financial reporting provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition and that the records are reliable for preparing consolidated financial statements and other financial information. We believe our policies and procedures provide reasonable assurance that our consolidated financial statements are prepared in accordance with applicable securities rules and regulations. Financial information displayed in other sections of this report has been reviewed to ensure consistency with the consolidated financial statements.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization including a written ethics and integrity policy that applies to all employees including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our Board of Directors approves the consolidated financial statements. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee) with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves and from the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors, and includes four directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors, and external auditors, to discuss reporting and control issues and ensures each party is properly discharging its responsibilities. The Audit Committee also considers the independence of the external auditors, reviews their fees and (subject to applicable securities laws) pre-approves the retention of the external auditors for any significant permitted non-audit services and the fee for such services. The internal and external auditors have access to the Committee without the presence of management.

(signed) "Charles W. Fischer"
President and Chief Executive Officer

(signed) "Marvin F. Romanow"
Executive Vice President
and Chief Financial Officer

REPORT OF INDEPENDENT AUDITORS

To the Shareholders of Nexen Inc.:

We have audited the consolidated balance sheet of Nexen Inc. as at December 31, 2003 and 2002 and the consolidated statements of income, cash flows and shareholders' equity for each of the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards in Canada and the United States of America. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Nexen Inc. as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years then ended in accordance with Canadian generally accepted accounting principles.

The financial statements of Nexen Inc. for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those financial statements in their report dated January 23, 2002. As described in Note 9, those financial statements have been revised to give effect to the discontinued operations. We audited the amounts reclassified as discontinued operations in the 2001 financial statements. Also, as described in Note 1(s), certain amounts in the 2001 financial statements have been reclassified to give effect to a change in generally accepted accounting principles in 2002. We audited the reclassification of amounts described in Note 1(s) that relates to the 2001 financial statements. In our opinion, the adjustments related to discontinued operations for 2001, and the reclassification of the amounts described in Note 1(s) are appropriate and have been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2001 financial statements of Nexen Inc., other than with respect to the adjustments and disclosures related to discontinued operations and the reclassification of the amounts described in Note 1(s), and accordingly, we do not express an opinion or any other form of assurance on the 2001 financial statements taken as a whole.

Calgary, Alberta
February 9, 2004

(signed) "Deloitte & Touche LLP"
Chartered Accountants

THIS REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS IS A COPY OF THE REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED.

REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS

To the Shareholders of Nexen Inc.:

We have audited the consolidated balance sheet of Nexen Inc. as at December 31, 2001 and 2000 and the consolidated statements of income, cash flows and shareholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards in Canada and the United States. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in accordance with generally accepted accounting principles in Canada.

Calgary, Alberta
January 23, 2002

(signed) "Arthur Andersen LLP"
Chartered Accountants

Nexen Inc.
Consolidated Statement of Income
For the Three Years Ended December 31, 2003
Cdn$ millions, except per share amounts

	2003	2002	2001
Revenues			
Net Sales	2,908	2,506	2,497
Marketing and Other (Note 12)	610	504	475
Gain (Loss) on Disposition of Assets	-	(8)	5
	3,518	3,002	2,977
Expenses			
Operating	751	751	758
Transportation and Other	461	475	400
General and Administrative	190	152	136
Depreciation, Depletion and Amortization (Note 4)	1,017	685	595
Exploration	200	181	260
Interest (Note 6)	105	109	112
	2,724	2,353	2,261
Income from Continuing Operations before Income Taxes	794	649	716
Provision for Income Taxes (Note 13)			
Current	210	223	216
Future	(40)	(12)	67
	170	211	283
Net Income from Continuing Operations	624	438	433
Net Income from Discontinued Operations (Note 9)	15	14	17
Net Income	639	452	450
Dividends on Preferred Securities, Net of Income Taxes (Note 7)	40	43	39
Net Income Attributable to Common Shareholders	599	409	411
Earnings Per Common Share from Continuing Operations ($/share)			
Basic (Note 8)	4.72	3.23	3.26
Diluted (Note 8)	4.67	3.19	3.22
Earnings Per Common Share ($/share)			
Basic (Note 8)	4.84	3.34	3.40
Diluted (Note 8)	4.79	3.30	3.36

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Balance Sheet
December 31, 2003 and 2002
Cdn$ millions, except share amounts

	2003	2002
Assets		
Current Assets		
Cash and Short-Term Investments	1,087	59
Accounts Receivable (Note 2)	1,423	988
Inventories and Supplies (Note 3)	270	256
Other	79	26
Total Current Assets	2,859	1,329
Property, Plant and Equipment (Note 4)	4,469	4,863
Goodwill	36	36
Future Income Tax Assets (Note 13)	108	263
Deferred Charges and Other Assets	153	69
	7,625	6,560
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-Term Borrowings (Note 6)	-	18
Current Portion of Long-Term Debt (Note 6)	291	-
Accounts Payable and Accrued Liabilities	1,404	1,194
Accrued Interest Payable	44	39
Dividends Payable	12	9
Total Current Liabilities	1,751	1,260
Long-Term Debt (Note 6)	2,485	1,844
Future Income Tax Liabilities (Note 13)	724	873
Dismantlement and Site Restoration	179	191
Other Deferred Credits and Liabilities	68	44
Shareholders' Equity (Note 7)		
Preferred and Subordinated Securities	364	724
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2003 – 125,606,107 shares		
2002 – 122,965,830 shares	513	440
Contributed Surplus	1	-
Retained Earnings	1,659	1,069
Cumulative Foreign Currency Translation Adjustment	(119)	115
Total Shareholders' Equity	2,418	2,348
Commitments, Contingencies and Guarantees (Note 10 and 13)		
	7,625	6,560

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(Signed) "Charles W. Fischer"
Director

(Signed) "David A. Hentschel"
Director

Nexen Inc.
Consolidated Statement of Cash Flows
For the Three Years Ended December 31, 2003
Cdn$ millions

	2003	2002	2001
Operating Activities			
Net Income from Continuing Operations	624	438	433
Net Income from Discontinued Operations	15	14	17
Charges and Credits to Income not Involving Cash (Note 14)	1,020	750	713
Exploration Expense	200	181	260
Changes in Non-Cash Working Capital (Note 14)	(320)	(46)	143
Other	(70)	(15)	-
	1,469	1,322	1,566
Financing Activities			
Proceeds from Long-Term Notes and Debentures (Note 6)	651	790	-
Repayment of Long-Term Notes and Debentures	-	-	(75)
Proceeds from (Repayment of) Term Credit Facilities, Net	93	(419)	(10)
Repayment of Short-Term Borrowings, Net	(18)	(33)	(17)
Proceeds from Subordinated Securities (Note 6)	613	-	-
Redemption of Preferred Securities (Note 7)	(340)	-	-
Dividends on Preferred Securities	(64)	(72)	(70)
Dividends on Common Shares	(40)	(37)	(37)
Issue of Common Shares	73	51	39
Other	(26)	(23)	-
	942	257	(170)
Investing Activities			
Capital Expenditures			
Exploration and Development	(1,276)	(1,477)	(1,162)
Proved Property Acquisitions	(164)	(4)	(122)
Chemicals, Corporate and Other	(54)	(144)	(120)
Proceeds on Disposition of Assets	293	49	5
Changes in Non-Cash Working Capital (Note 14)	(18)	7	(18)
Other	-	-	(52)
	(1,219)	(1,569)	(1,469)
Effect of Exchange Rate Changes on Cash and Short-Term Investments	(164)	(12)	24
Increase (Decrease) in Cash and Short-Term Investments	1,028	(2)	(49)
Cash and Short-Term Investments – Beginning of Year	59	61	110
Cash and Short-Term Investments – End of Year	1,087	59	61

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Statement of Shareholders' Equity
For the Three Years Ended December 31, 2003
Cdn$ millions

	Preferred and Subordinated Securities (Note 7)	Common Shares (Note 7)	Contributed Surplus	Retained Earnings	Cumulative Foreign Currency Translation Adjustment
December 31, 2000	724	350	-	323	63
Exercise of Stock Options	-	16	-	-	-
Issue of Common Shares	-	23	-	-	-
Net Income	-	-	-	450	-
Dividends on Preferred Securities, Net of Income Taxes	-	-	-	(39)	-
Dividends on Common Shares	-	-	-	(37)	-
Translation Adjustment, Net of Income Taxes	-	-	-	-	31
December 31, 2001	724	389	-	697	94
Exercise of Stock Options	-	27	-	-	-
Issue of Common Shares	-	24	-	-	-
Net Income	-	-	-	452	-
Dividends on Preferred Securities, Net of Income Taxes	-	-	-	(43)	-
Dividends on Common Shares	-	-	-	(37)	-
Translation Adjustment, Net of Income Taxes	-	-	-	-	21
December 31, 2002	724	440	-	1,069	115
Exercise of Stock Options	-	50	-	-	-
Issue of Common Shares	-	23	-	-	-
Redemption of Preferred Securities (Note 7)	(393)	-	-	-	-
Gain on Redemption of Preferred Securities, Net of Income Taxes (Note 7)	-	-	-	31	-
Issue of Subordinated Securities (Note 7)	33	-	-	-	-
Net Income	-	-	-	639	-
Dividends on Preferred Securities, Net of Income Taxes	-	-	-	(40)	-
Dividends on Common Shares	-	-	-	(40)	-
Stock Based Compensation Expense (Note 7)	-	-	1	-	-
Translation Adjustment, Net of Income Taxes	-	-	-	-	(234)
December 31, 2003	364	513	1	1,659	(119)

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Notes to Consolidated Financial Statements
Cdn$ millions except as noted

1. ACCOUNTING POLICIES
Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and US GAAP on the Consolidated Financial Statements is disclosed in Note 16. We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Actual results can differ from those estimates.

(a) Principles of Consolidation
The Consolidated Financial Statements include the accounts of Nexen Inc. and our subsidiary companies (Nexen, we or our). All subsidiary companies are wholly owned and all material intercompany accounts and transactions have been eliminated. We conduct most exploration, development and production activities in our oil and gas business and Syncrude jointly with others and our accounts reflect only Nexen's proportionate interest.

(b) Accounts Receivable
Accounts receivable are recorded based on our revenue recognition policy (see Note 1(i)). Our allowance for doubtful accounts provides for specific doubtful receivables.

(c) Inventories and Supplies
Inventories and supplies for our oil and gas and chemicals operations are stated at the lower of cost and net realizable value. Cost is determined on the first-in, first-out method or average basis.

After October 25, 2002, inventories for our marketing operation are accounted for at the lower of cost and net realizable value determined on an average basis. Prior to that, these inventories were reported at market value.

(d) Property, Plant and Equipment (PP&E)
Property, plant and equipment is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, major maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We follow successful efforts accounting for our oil and gas business. All property acquisition costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the acquisition costs are reclassified to proved property acquisition costs. Exploration drilling costs are capitalized until we determine whether the well is successful. If successful, the costs are reclassified to proved property costs. If unsuccessful, the exploration drilling costs are expensed to earnings. All other exploration costs, including geological and geophysical and annual lease rentals are expensed to earnings as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established and we intend to proceed with development. We defer these costs in PP&E until the commencement of commercial operations or production. Otherwise, development costs are expensed as incurred. Development costs include pre-operating revenues and costs.

We periodically evaluate our PP&E to ensure that the carrying value of properties on the balance sheet is recoverable. If carrying value exceeds the sum of undiscounted future cash flows, the property's value is impaired. The property is assigned a fair value equal to its estimated total future cash flows, discounted for the time value of money, and we expense the excess carrying value to depreciation, depletion and amortization. Our cash flow estimates require assumptions about future commodity prices, operating costs and other factors. Actual results can differ from those estimates.

(e) Depreciation, Depletion and Amortization (DD&A)
Under successful efforts accounting, we deplete oil and gas costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs over proved reserves. We depreciate other plant and equipment costs, including our chemicals facilities, using the straight-line method based on the estimated useful lives of the assets, which range from 3 years to 30 years.

Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

(f) Carried Interest

We conduct certain international operations jointly with foreign governments in accordance with production sharing agreements. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs are recorded in operating expense when incurred and capital costs are recorded in PP&E and are expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(g) Dismantlement and Site Restoration

We provide for dismantlement and site restoration costs on our resource properties, facilities, production platforms, pipelines and chemicals facilities based on estimates established by current legislation and industry practices. We record an annual provision for these costs in DD&A based on proved reserves or estimated remaining asset lives. Actual dismantlement and site restoration expenditures incurred in the year reduce the provision.

(h) Goodwill

Goodwill and intangible assets with an indefinite useful life are recorded at cost and are not amortized. We test for impairment at least annually based on estimated future cash flows. No goodwill impairment writedowns were required.

(i) Revenue Recognition

Crude Oil and Natural Gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada and the US, our customers typically take title when the crude oil and natural gas reaches the end of the pipeline. For our international operations, our customers take title when the crude oil is loaded onto the tanker. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities, and underlifts as assets. We settle these over time as liftings are equalized, or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty payments to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty payments. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations. See Note 1(f).

Chemicals

Revenue from our chemicals operations is recognized when our products reach our customers.

Marketing

Substantially all of the physical purchase and sale contracts entered into by our marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively derivative instruments) held by our marketing operation are stated at fair value on the balance sheet date. We record any change in fair value as a gain or loss in marketing and other. Any margin realized by our marketing department on the sale of our proprietary oil and gas production is included in marketing and other.

(j) Income Taxes

We follow the liability method of accounting for income taxes (see Note 13). This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, since we intend to invest such earnings indefinitely in foreign operations.

(k) Petroleum Resource Rent Tax

We treat Petroleum Resource Rent Tax on our Australian oil and gas operations as a royalty and deduct it from sales. Any temporary differences between financial statement and tax reported amounts, including depletion, dismantlement and site restoration, are recorded as a future liability or asset using current tax rates.

(l) Foreign Currency Translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars as follows:

- assets and liabilities using exchange rates at the balance sheet dates; and
- revenues and expenses using the average exchange rates throughout the year.

Gains and losses resulting from this translation are included in the cumulative foreign currency translation adjustment in shareholders' equity.

Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from translation, except on our designated US-dollar debt, are included in income. We have designated US-dollar debt as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other in the Consolidated Statement of Income.

(m) Capitalized Interest

Prior to commercial production, we capitalize interest on major development projects using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest expense.

(n) Derivative Instruments

Non-Trading Activities

We use derivative instruments such as physical purchase and sales, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Note 5). Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives. We recognize gains and losses on the derivative instruments in the same period as the gains or losses on the hedged items are recognized. If effective correlation ceases, hedge accounting is terminated and future changes in the market value of the derivative instrument are included as gains or losses in marketing and other in the period of change.

Trading Activities

Our marketing operation uses derivative instruments for marketing and trading crude oil and natural gas including:

- commodity contracts settled with physical delivery;
- exchange-traded futures and options; and
- non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in market value as net gains or losses in marketing and other during the period of change. The fair value of these instruments is recorded as accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond 12 months we record them as deferred charges and other assets or other deferred credits and liabilities.

(o) Employee Benefits

The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses which exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. We measure the plan assets and the accrued benefit obligation on October 31 each year.

(p) Stock-Based Compensation

We estimate the fair value of stock options on the grant date using the Generalized Black-Scholes option pricing model with the assumptions described in Note 7(f). For options granted prior to January 1, 2003, we use the intrinsic value based method and recognize no compensation expense. For options granted after January 1, 2003, we use the fair-value based method and expense them over the vesting period.

We provide stock appreciation rights to employees as described in Note 7. Obligations are accrued as compensation expense over the vesting period of the stock appreciation rights.

(q) Cash and Short-Term Investments

Cash and short-term investments are instruments that mature within three months of their purchase.

(r) Transportation

We pay to transport the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as a cost to us and is recorded as transportation and other.

(s) Changes in Accounting Principles

Stock Based Compensation

During the year, we prospectively adopted the fair-value method of accounting for stock options granted to employees and directors. We record stock based compensation expense on the Consolidated Statement of Income as general and administrative expense for all options granted on or after January 1, 2003, with a corresponding increase recorded as contributed surplus. Compensation expense for options granted during 2003 is based on the estimated fair values at the time of the grant and we recognize the expense over the vesting period of the option. We recognized $1 million of compensation expense for options granted during 2003. For options granted prior to January 1, 2003, we continue to disclose the pro forma earnings impact of related stock based compensation expense (see Note 7(g)).

Presentation of Transportation

During 2002, we adopted the new interpretation of the Emerging Issues Committee relating to the presentation of costs for which we are reimbursed. We pay for the transportation of the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. Under the new interpretation, this transportation should be presented as a cost to us. Previously, we netted this cost against our revenue. Effective October 1, 2002, we show these costs as transportation and other on the Consolidated Statement of Income, resulting in the following increases:

	2002	2001
Net Sales	35	32
Marketing and Other	423	342
Transportation and Other	458	374

(t) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2003.

2. ACCOUNTS RECEIVABLE

	2003	2002
Trade		
Oil and Gas		
Marketing	1,078	574
Other	263	330
Chemicals and Other	47	59
	1,388	963
Non-Trade	50	34
	1,438	997
Allowance for Doubtful Receivables	(15)	(9)
	1,423	988

3. INVENTORIES AND SUPPLIES

	2003	2002
Finished Products		
Oil and Gas		
Marketing	138	130
Other	16	-
Chemicals and Other	12	13
	166	143
Work in Process	6	6
Field Supplies	98	107
	270	256

4. PROPERTY, PLANT AND EQUIPMENT

	2003			2002		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	656	489	167	711	531	180
Yemen - Carried Interest	1,242	1,008	234	1,343	1,115	228
Canada	2,879	1,428	1,451	3,098	1,137	1,961
United States	2,095	854	1,241	2,186	959	1,227
Australia	172	168	4	209	184	25
Other Countries	313	198	115	305	198	107
Marketing	157	56	101	86	40	46
	7,514	4,201	3,313	7,938	4,164	3,774
Syncrude	811	141	670	628	139	489
Chemicals	760	371	389	789	345	444
Corporate and Other	168	71	97	213	57	156
	9,253	4,784	4,469	9,568	4,705	4,863

The above table includes capitalized costs of $630 million (2002 - $585 million) relating to unproved properties and projects under construction or development. These costs are not being depreciated, depleted or amortized.

Our 2003 depreciation, depletion and amortization expense in the Consolidated Statement of Income includes an impairment charge of $269 million ($175 million net of income tax) relating to certain Canadian oil and gas properties. The impairment results from negative reserve revisions and is largely attributable to Canadian heavy oil properties. The revisions resulted from changes in late field-life economic assumptions, changes in proved undeveloped reserves based on drilling results and geological mapping, and reassessments of estimated future production profiles. Even though we expect to recover the carrying value of our Canadian oil and gas properties in aggregate from their future cash flows, under successful efforts accounting, we are required to make impairment assessments on a property-by-property basis. The impairment charge represents the write-down of the carrying value of the impaired properties to their estimated fair value. We have determined the estimated fair value of the impaired properties based on the present value of the expected future net cash flows we expect to receive from the properties.

We incurred $20 million (2002 - $6 million) related to research and development activity. Costs of $14 million (2002 - $6 million) were recorded in other expense on the Consolidated Statement of Income. The remaining costs have been deferred and are included in PP&E.

	2003	2002
Development Costs Deferred, Beginning of Year	-	-
Deferred in the Year	6	-
Amortized in the Year	-	-
Development Costs Deferred, End of Year	6	-

5. DERIVATIVE INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The nature of our operations and long-term debt expose us to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. We recognize these risks and manage our operations to minimize our exposure to the extent practical and, to a lesser extent, using derivative instruments. Our marketing operation uses derivative instruments to manage its exposure to commodity price fluctuations and for trading purposes. We use physical purchases and sales contract, exchange-traded futures and options and non-exchange traded forwards, swaps and options, which may be settled in cash or by delivery of the physical commodity. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and regularly review our derivative activities and all outstanding positions.

The carrying value, fair value, and unrecognized gains or losses on our outstanding derivatives and long-term financial assets and liabilities at December 31 are:

Cdn$ millions	2003			2002		
Net Assets/(Liabilities)	Carrying Value	Fair Value	Unrecognized Gain/(Loss)	Carrying Value	Fair Value	Unrecognized Gain/(Loss)
Commodity Price Risk – Non-Trading Activities						
Natural Gas Swaps	-	-	-	-	2	2
Future Sale of Oil and Gas Production	-	(3)	(3)	-	-	-
Commodity Price Risk – Trading Activities						
Crude Oil and Natural Gas	106	106	-	3	3	-
Future Sale of Gas Inventory	-	(11)	(11)	-	-	-
Foreign Currency Risk	-	(1)	(1)	-	(3)	(3)
Total Derivatives	106	91	(15)	3	2	(1)
Financial Assets and Liabilities						
Long-Term Debt	(2,485)	(2,706)	(221)	(1,844)	(1,948)	(104)
Preferred and Subordinated Securities	(364)	(319)	45	(724)	(756)	(32)
	(2,849)	(3,025)	(176)	(2,568)	(2,704)	(136)

The estimated fair value of all derivative instruments is based on quoted market prices and, if not available, on estimates from third-party brokers or dealers. The carrying value of cash and short-term investments, amounts receivable and short-term obligations approximates their fair value because the instruments are near maturity.

(a) Commodity price risk management

Non-Trading Activities

We generally sell our crude oil and natural gas under short-term market based contracts.

Natural gas swaps

During 2002 and 2001, we purchased fixed-to-floating swaps to modify the terms of certain fixed-price natural gas contracts as we prefer to receive an index-based price for our natural gas. Under the terms of these contracts, we were required to deliver 4 million cubic feet per day of natural gas to counterparties at prices ranging from \$3.06 to \$6.08 per thousand cubic feet. On settlement, we either paid or received cash for the difference between the contract and floating rates. These swaps expired in 2003.

Future sale of oil and gas production

In March 2003, we sold WTI and NYMEX gas forward contracts for the next 12 months to lock-in part of the return on the remaining 40% interest acquired in the Aspen field. The forward contracts fix our oil and gas prices at the contract prices for the hedged volumes, less applicable price differentials. Unrecognized losses on these contracts are:

	Hedged Volumes	Term	Average Price	Unrecognized Loss
			(US$)	(Cdn$ millions)
Fixed WTI Price	5,000 bbls/d	April 2003 – March 2004	28.50/bbl	(2)
Fixed NYMEX Price	12,000 mmbtu/d	April 2003 – March 2004	5.35/mmbtu	(1)
				(3)

Trading Activities

Crude oil and natural gas

Our marketing operation engages in crude oil and natural gas marketing activities to enhance prices from the sale of our oil and gas production, and for energy trading. As part of our strategy:

- we enter into contracts to purchase and sell crude oil and natural gas;
- we inject and withdraw natural gas into and from storage to take advantage of seasonal changes in demand; and
- we create net open positions to take advantage of market conditions.

These contracts and positions expose us to changes in market prices. To mitigate this price risk, we use energy-related futures, forwards, swaps and options. We also balance physical and financial contracts in terms of volumes, timing of performance and delivery obligations.

Total carrying value of derivative energy contracts

Amounts related to derivative energy instruments held by our marketing operation are equal to fair value as we use mark-to-market accounting, and are as follows at December 31:

Cdn $millions	**2003**	**2002**
Accounts Receivable	102	42
Deferred Charges and Other Assets [1]	63	14
Total Derivative Energy Contract Assets	165	56
Accounts Payable and Accrued Liabilities	34	46
Other Deferred Credits and Liabilities [1]	25	7
Total Derivative Energy Contract Liabilities	59	53
Total Derivative Energy Contract Net Assets	106	3

Note:

[1] These derivative instruments settle beyond 12 months and are considered non-current.

Future sale of gas inventory

Our marketing inventory is carried at the lower of cost and net realizable value while generally our derivative contracts are stated at market value. To better match our accounting with our economic exposure, we began designating certain NYMEX natural gas futures contracts and AECO/NYMEX basis swaps in July 2003 as hedges of our price risk on the future sale of our inventory. We have designated in writing some of our financial contracts as cash flow hedges. The principal terms of these outstanding contracts and the unrecognized losses at December 31, 2003 are:

	Hedged Volumes	Month	Average Price	Unrecognized Loss
	(mmcf)		(US$ mcf)	(Cdn$ millions)
NYMEX Natural Gas Futures	5,610	January 2004	4.91 – 6.19	(6)
	3,850	February 2004	4.93 – 6.09	(3)
	150	March 2004	4.85	-
	1,500	April 2004	4.76	(1)
AECO/NYMEX Basis Swaps	380	January 2004	5.51	(1)
	300	February 2004	5.15	-
				(11)

Our marketing strategy enables our marketing operation to generate income using competitive information from marketing activities, but it exposes us to risks of loss from fluctuating market prices. Our exposure is restricted to prescribed limits and is monitored daily using value-at-risk measures, stress testing and scenario analysis. The value-at-risk calculation estimates the maximum probable loss, given a 95% confidence level, that we would incur if our open positions were unwound over two days. Our net margins from trading activities and our value-at-risk are:

	2003	**2002**	**2001**
Net Revenue	568	496	438
Less: Transportation	(398)	(423)	(342)
Other	(1)	-	-
	169	73	96
Value-at-Risk			
Year End	21	19	19
Average	20	17	13

(b) Foreign currency exchange rate risk management

Many of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas and chemicals operations outside Canada; and
- short-term and long-term borrowings.

We manage our exposure to fluctuations between the US and Canadian dollar by minimizing the need to convert between the two currencies. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Until 2003, all of our US-dollar debt was designated as a hedge against our net investment in foreign operations. In early 2003, we de-designated our unsecured syndicated term credit facilities from the hedge as funds drawn were used to fund US-dollar working capital in our Canadian operations. Our remaining US-dollar debt continued to be designated as a hedge against our net investment in foreign operations. In the third quarter of 2003, we re-designated our unsecured syndicated term credit facilities, as US-dollar funds drawn were no longer funding working capital in our Canadian operations. The US-dollar debt issued in November 2003 to re-finance existing designated US-dollar debt was designated as part of the hedge in February 2004.

The foreign exchange gains or losses related to the designated debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. The exchange gains and losses on the unsecured syndicated term credit facilities during the de-designated period were included in marketing and other. Foreign exchange gains or losses on the November 2003 debt issues were included in marketing and other. Our net investment in foreign operations and our designated US-dollar long-term debt at December 31 are as follows:

(US$ millions)	2003	2002
Net Investment in Foreign Operations	1,574	1,389
Long-Term Debt	925	962

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. At December 31, 2003, we held a foreign currency derivative instrument that obligates us and the counterparty to exchange principal and interest amounts. In November 2006, we will pay US$37 million and receive Cdn $50 million (see Note 6).

(c) Interest rate risk management

We use fixed and floating rate debt to finance our operations. The floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2003, fixed-rate borrowings comprised 100% (2002 – 100%) of our long-term debt at an effective average rate of 6.8% (2002 - 7.4%). During the year we periodically drew on our floating rate unsecured syndicated term credit facilities. We had no interest rate swaps outstanding in 2003 or 2002.

(d) Credit risk management

A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international customers. We are also exposed to possible non-performance by derivative instrument counterparties. We assess the financial strength of our customer and counterparty base, including those involved in marketing and other commodity arrangements and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event downgrades to non-investment grade credit ratings occur. Credit risk, including credit concentrations are routinely reported to our Risk Management Committee. We also use standard agreements that net positive and negative exposures of a single counterparty. We believe this minimizes our overall credit risk.

6. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

	2003	2002
Unsecured Syndicated Term Credit Facilities (a)	-	-
Unsecured Redeemable Notes, due 2004 (b)	291	355
Unsecured Redeemable Debentures, due 2006 (c)	98	108
Unsecured Redeemable Medium Term Notes, due 2007 (d)	150	150
Unsecured Redeemable Medium Term Notes, due 2008 (e)	125	125
Unsecured Redeemable Notes, due 2013 (f)	646	-
Unsecured Redeemable Notes, due 2028 (g)	258	316
Unsecured Redeemable Notes, due 2032 (h)	646	790
Unsecured Subordinated Debentures, due 2043 (i)	562	-
	2,776	1,844
Less: Current Portion of Long-Term Debt	291	-
	2,485	1,844

(a) Unsecured syndicated term credit facilities

Nexen has committed, unsecured, revolving term credit facilities totalling $1,656 million, $410 million of which is available until 2007 and $1,246 million until 2008. The lenders have the option to extend the terms annually. No repayments are required until the end of the availability periods. Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime loans or US-dollar base rate loans. Interest is payable monthly at a floating rate. During 2003, the weighted average interest rate was 2.0% (2002 – 2.5%).

(b) Unsecured redeemable notes, due 2004

During February 1999, we issued US$225 million of notes. Interest is payable semi-annually at a rate of 7.125%, and the principal was repaid at par in February 2004. The notes have been included as a current liability on the Consolidated Balance Sheet.

(c) Unsecured redeemable debentures, due 2006

During November 1996, we issued $100 million of unsecured 10-year redeemable debentures. Interest is payable semi-annually at a rate of 6.85% and the principal is to be repaid in November 2006. In December 1996, $50 million of this obligation was effectively converted through a currency exchange contract with a Canadian chartered bank to a US$37 million liability bearing interest at 6.75% for the term of the debentures. We may redeem part or all of the debentures at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the debentures plus 0.1%.

(d) Unsecured redeemable medium term notes, due 2007

During July 1997, we issued $150 million of notes. Interest is payable semi-annually at a rate of 6.45% and the principal is to be repaid in July 2007. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(e) Unsecured redeemable medium term notes, due 2008

During October 1997, we issued $125 million of notes. Interest is payable semi-annually at a rate of 6.3% and the principal is to be repaid in June 2008. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(f) Unsecured redeemable notes, due 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05% and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%. Included in deferred charges and other assets at December 31, 2003 are issue costs of US$8 million which are amortized to earnings over the term of the issue.

(g) Unsecured redeemable notes, due 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.25%.

(h) Unsecured redeemable notes, due 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.375%. Included in deferred charges and other assets at December 31, 2003 is a debt discount of US$13 million (2002 – US$14 million) which is amortized to earnings over the term of the debt issue.

(i) Unsecured subordinated debentures, due 2043

On November 4, 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly in cash. We may redeem part or all of the debentures at any time on or after November 8, 2008. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares. As a result, we are required to classify the carrying value of the debentures into debt and equity components. The debt component of US$435 million represents the present value of future interest payments. The remaining US$25 million represents the equity component and has been recorded in shareholders' equity (see Note 7(a)). Included in deferred charges and other assets at December 31, 2003 are issue costs of US$12 million which are amortized to earnings over the term of the issue.

(j) Debt repayments

2004	291
2005	-
2006	98
2007	150
2008	125
Thereafter	2,112
	2,776

(k) Debt covenants

Most of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2003, we were in compliance with all covenants.

(l) Short-term borrowings

Nexen has unsecured operating loan facilities of approximately $328 million. Interest is payable at floating rates and the facilities are subject to periodic reviews. During 2003, the weighted average interest rate on short-term borrowings was 2.4% (2002 – 2.3%).

Occasionally, we sell the future proceeds of our accounts receivable; however, we retain a 10% exposure to related credit losses. At December 31, 2003, we did not sell any of our accounts receivable proceeds. At December 31, 2002 we sold $178 million of accounts receivable and retained a credit exposure of $18 million which was included in short-term borrowings. During 2003, this credit exposure was eliminated as the receivable proceeds were fully collected.

(m) Interest expense

	2003	**2002**	**2001**
Long-Term Debt	140	134	106
Other	8	6	6
Total	148	140	112
Less: Capitalized	43	31	-
	105	109	112

Capitalized interest relates to and is included as part of the cost of oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings.

7. SHAREHOLDERS' EQUITY

(a) Preferred and Subordinated Securities

	Principal Amount	Interest Rate	Maturity Date	First Call Date
	(US$ millions)	(%)		
Preferred Securities	259	9.75	October 30, 2047	October 30, 2003
Preferred Securities	217	9.375	March 31, 2048	February 9, 2004
Subordinated Securities (Note 6(i))	25	7.35	November 4, 2043	November 8, 2008

Nexen may redeem part or all of the preferred securities at any time on or after their call date. We may defer, subject to certain conditions, up to 20 consecutive quarterly interest payments and may satisfy our interest, principal or redemption payments by issuing common shares. Interest is payable quarterly. Since we have the unrestricted ability to settle the interest, principal and redemption payments by issuing common shares, the preferred securities are classified as equity. We record the principal amount in shareholders' equity and interest payments, net of income taxes, are classified as dividends and charged directly to retained earnings.

On December 15, 2003, we redeemed $393 million (US$259 million) of preferred securities at par. On redemption we realized a gain of $31 million, net of income tax, for the difference between the carrying value and the settlement amount. This gain related to the change in foreign exchange rates between the date of issue and settlement, and has been included in retained earnings.

On January 9, 2004, we gave notice to redeem our US$217 million preferred securities. These securities were redeemed at par on February 9, 2004. The realized foreign exchange gain of $34 million, net of income taxes, for the difference between the carrying value and the settlement amount was included in retained earnings in 2004.

(b) Authorized capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

(c) Issued common shares and dividends

(thousands of shares)	2003	2002	2001
Beginning of Year	122,966	121,202	119,855
Issue of Common Shares for Cash:			
Exercise of Stock Options	1,964	1,090	648
Dividend Reinvestment Plan	476	500	533
Employee Flow-through Shares	200	174	166
End of Year	125,606	122,966	121,202
Dividends per Common Share ($/share)	0.325	0.30	0.30
Cash Consideration (Cdn$ millions)			
Exercise of Stock Options	50	27	16
Dividend Reinvestment Plan	15	17	17
Employee Flow-through Shares	8	7	6
	73	51	39

At December 31, 2003, there were 1,307,305 (2002 – 1,783,968; 2001 – 489,329) common shares reserved for issuance under the Dividend Reinvestment Plan.

(d) Stock Options Granted, Exercised and Forfeited

We have granted options to purchase common shares to directors, officers and employees. Each option permits the holder to purchase one Nexen common share at the stated exercise price. Options granted prior to February 2001 vest over 4 years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over 3 years and are exercisable on a cumulative basis over 5 years. At the time of grant, the exercise price equals the market price. The following options have been granted:

	Options (thousands)	Weighted-Average Exercise Price ($/option)
December 31, 2000	7,976	29
Granted	1,645	31
Exercised	(648)	24
Forfeited	(142)	30
December 31, 2001	8,831	30
Granted	1,788	31
Exercised	(1,090)	25
Forfeited	(53)	30
December 31, 2002	9,476	30
Granted	1,877	44
Exercised	(1,964)	28
Forfeited	(186)	32
December 31, 2003	9,203	34
Options exercisable at December 31		
2001	4,232	27
2002	5,113	29
2003	5,067	30

At December 31, 2003 there were 9,787,833 (2002 – 9,759,545; 2001 – 10,896,060) common shares reserved for issuance under the stock option plan and there were 9,203,121 (2002 – 9,475,985; 2001 – 8,831,235) outstanding options.

(e) Exercise Price Range

	Outstanding Options			Exercisable Options	
	Number of Options (thousands)	Weighted-Average Exercise Price ($/option)	Weighted-Average Years to Expiry (years)	Number of Options (thousands)	Weighted-Average Exercise Price ($/option)
$12.13 to $19.99	416	18	5	416	18
$20.00 to $24.99	176	23	3	176	23
$25.00 to $29.99	1,828	28	5	1,709	28
$30.00 to $34.99	2,729	33	4	1,151	32
$35.00 to $39.99	2,169	36	7	1,607	36
$40.00 to $44.99	1,885	44	5	8	40
	9,203			5,067	

(f) Estimated Fair-Value of Stock Options

We estimate the fair value of stock options issued using the Generalized Black-Scholes option pricing model under the following assumptions:

	2003	2002	2001
Weighted-Average Fair Value ($/option)	10.10	9.08	12.24
Risk-Free Interest Rate (%)	3.6	3.6	5.1
Estimated Hold Period Prior to Exercise (years)	3	3	5
Volatility in the Price of Nexen's Common Shares (%)	30	35	40
Dividends per Common Share ($/share)	0.40	0.30	0.30

(g) Pro Forma Net Income – Fair-Value Method of Accounting for Stock Options

The following shows pro forma net income and earnings per common share had we applied the fair-value method to account for all stock options outstanding that were granted up to December 31, 2002. Stock options granted after that date have been expensed as general and administrative costs.

	2003	2002	2001
Fair Value of Stock Options Granted	25	22	25
Less: Fair Value of Stock Options Expensed	(1)	-	-
	24	22	25
Net Income Attributable to Common Shareholders			
As Reported	599	409	411
Pro Forma	575	387	386
Earnings Per Common Share ($/share)			
Basic as Reported	4.84	3.34	3.40
Pro Forma	4.65	3.16	3.20
Diluted as Reported	4.79	3.30	3.36
Pro Forma	4.60	3.13	3.16

(h) Stock Appreciation Rights

Under our stock appreciation rights plan established in 2001, employees are entitled to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The vesting period and other terms of the plan are similar to the stock option plan. The total rights granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares.

	2003	2002	2001
Weighted Average Exercise Price ($/right)	42.67	33.94	31.17
Rights Expensed ($ millions)	14	2	-

The following stock appreciation rights have been granted:

	Rights (thousands)
December 31, 2000	-
Granted	915
December 31, 2001	915
Granted	908
Exercised	(3)
Forfeited	(8)
December 31, 2002	1,812
Granted	1,017
Exercised	(363)
Forfeited	(62)
December 31, 2003	2,404

8. EARNINGS PER COMMON SHARE

We calculate basic earnings per common share from continuing operations using net income from continuing operations less dividends on preferred securities, net of income taxes, divided by weighted average number of common shares outstanding. We calculate basic earnings per common share using net income attributable to common shareholders and the weighted-average number of common shares outstanding. We calculate diluted earnings per common share from continuing operations and diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2003	2002	2001
Weighted-average number of common shares outstanding	123.8	122.4	120.7
Shares issuable pursuant to stock options	6.2	8.1	4.7
Shares to be purchased from proceeds of stock options	(5.1)	(6.7)	(3.3)
Weighted-average number of diluted common shares outstanding	124.9	123.8	122.1

In calculating diluted earnings per common share for the year ended December 31, 2003, we excluded 2,817,023 options (2002 – 46,167; 2001 – 2,992,903), because the exercise price was greater than the annual average market price of our common shares in those periods. During these three years, outstanding stock options were the only dilutive instrument.

9. DISCONTINUED OPERATIONS

On August 28, 2003, we sold certain non-core conventional light oil properties in southeast Saskatchewan in Canada. Net proceeds were $268 million and there was no gain or loss on the sale. The results of operations from these properties are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

	2003	2002	2001
Revenues			
Net Sales	66	100	96
Expenses			
Operating	16	25	23
Depreciation, Depletion and Amortization	20	35	30
Exploration	1	8	5
Income before Income Taxes	29	32	38
Future Income Taxes	14	18	21
Net Income from Discontinued Operations	15	14	17
Earnings Per Common Share ($/share)			
Basic (Note 8)	0.12	0.11	0.14
Diluted (Note 8)	0.12	0.11	0.14

Assets and liabilities on the Consolidated Balance Sheet include the following amounts for discontinued operations.

	December 31 2003	December 31 2002
Accounts Receivable	-	12
Property, Plant and Equipment	-	289
Accounts Payable and Accrued Liabilities	-	9
Dismantlement and Site Restoration	-	10

10. COMMITMENTS, CONTINGENCIES AND GUARANTEES

	2004	2005	2006	2007	2008	Thereafter
Operating leases	33	38	20	19	16	91
Transportation commitments	212	94	78	52	33	111
	245	132	98	71	49	202

We have a number of lawsuits and claims pending including income tax reassessments (see Note 13), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During 2003, total rental expense was $49 million (2002 - $47 million; 2001 - $42 million).

From time to time we enter into certain types of contracts that require us to indemnify parties against possible third party claims particularly when these contracts relate to divestiture transactions. On occasion we may provide routine indemnifications. The terms of such obligations vary and generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. Our Risk Management Committee actively monitors our exposure to the above risks and obtains insurance coverage to satisfy potential or future claims as necessary. We believe that payments, if any, related to such matters would not have a material adverse effect on our liquidity, financial condition or results of operations.

11. PENSION AND OTHER POST RETIREMENT BENEFITS

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, which together cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our share of this plan. Under these defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation.

(a) Defined Benefit Pension Plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2003		2002	
Change in Projected Benefit Obligation (PBO)	Nexen	Syncrude	Nexen	Syncrude
Beginning of Year	164	68	163	63
Service Cost	7	3	7	3
Interest Cost	11	4	10	4
Plan Participants' Contributions	2	-	2	-
Actuarial Loss/(Gain)	14	6	(11)	-
Benefits Paid	(6)	(2)	(7)	(2)
End of Year [1]	192	79	164	68
Change in Fair Value of Plan Assets				
Beginning of Year	127	37	136	41
Actual Return on Plan Assets	15	7	(7)	(3)
Employer's Contribution	16	2	3	1
Plan Participants' Contributions	2	-	2	-
Benefits Paid	(6)	(2)	(7)	(2)
End of Year	154	44	127	37
Reconciliation of Funded Status				
Funded Status [2]	(38)	(35)	(37)	(31)
Unamortized Transitional Obligation	1	-	1	-
Unamortized Prior Service Costs	5	-	6	1
Unamortized Net Actuarial Loss	26	25	19	23
Pension Liability	(6)	(10)	(11)	(7)
Pension Liability Recognized:				
Deferred Charges and Other Assets	15	-	7	-
Other Deferred Credits and Liabilities	(21)	(10)	(18)	(7)
Pension Liability	(6)	(10)	(11)	(7)
Assumptions (%)				
Discount Rate	6.25 [4]	6.00 [4]	6.75 [3]	6.50 [3]
Long-Term Rate of Employee Compensation Increase	4.00 [4]	4.00 [4]	4.00 [3]	4.00 [3]
Long-Term Annual Rate of Return on Plan Assets [5]	7.00 [4]	9.00 [4]	7.00 [3]	9.00 [3]

Notes:

1 Nexen's employee pension plan's accumulated benefit obligation (the projected benefit obligation excluding future salary increases) was $139 million at December 31, 2003. Nexen's supplemental pension plan's accumulated benefit obligation was $19 million at December 31, 2003. Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $56 million at December 31, 2003.

2 Includes unfunded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. At December 31, 2003, the PBO for supplemental benefits was $29 million (2002 - $26 million).

3 The assumptions have been used to calculate the October 31, 2002 PBO and the 2003 recognized expense.

4 The assumptions have been used to calculate the October 31, 2003 PBO and the 2004 recognized expense for Nexen. There were no changes to the assumptions between the measurement date and December 31, 2003. Syncrude's measurement date was December 31, 2003.

5 The long-term rate of return on plan assets assumption is based on a mix of historical market returns from debt and equity securities.

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2003	2002	2001
Nexen			
Cost of Benefits Earned by Employees	7	7	5
Interest Cost on Benefits Earned	11	10	9
Expected Return on Plan Assets	(9)	(10)	(10)
Net Amortization and Deferral	1	1	-
Net	10	8	4
Syncrude			
Cost of Benefits Earned by Employees	3	3	2
Interest Cost on Benefits Earned	4	4	4
Expected Return on Pension Plan Assets	(3)	(4)	(4)
Net Amortization and Deferral	1	1	-
Net	5	4	2
Total	15	12	6

(b) Plan Asset Allocation at December 31

Our investment goal for the assets in our defined benefit pension plan is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies mandated by our Board of Directors and Pension Committee. Nexen's investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations, that are traded on recognized stock exchanges. A fund's market value may not exceed a maximum in any one issuer at the time of purchase, as set out by our investment policy provided to fund managers. Allowable and prohibited investment types are also prescribed in Nexen's investment policy.

Syncrude's pension plan is governed and administered separately from ours. Syncrude's investment assets are subject to a similar investment goal, policy and strategy.

(%)	Expected 2004	2003	2002
Nexen			
Equity Securities	60	52	54
Debt Securities	40	40	42
Real Estate	-	-	-
Other	-	8	4
Total	100	100	100
Syncrude			
Equity Securities	70	72	70
Debt Securities	30	28	30
Real Estate	-	-	-
Other	-	-	-
Total	100	100	100

(c) Defined Contribution Pension Plans

Under these plans, pension benefits are based on plan contributions. During 2003, Canadian pension expense for these plans was $4 million (2002 – $3 million; 2001 – $3 million). During 2003, US pension expense for these plans was $3 million (2002 – $3 million; 2001 – $3 million).

(d) Post-Retirement Benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. These costs are fully accrued as compensation in the period employees work; however, these future obligations are not funded. The present value of Nexen employees' future post retirement benefits in 2003 was $5 million (2002 - $4 million). Nexen's share of post-retirement and post-employment benefits related to Syncrude in 2003 was $6 million (2002 - $6 million).

(e) Employer Funding Contributions and Benefit Payments

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law. For our defined contribution plans, we always match the employee contribution and no further obligation exists. Our funding contributions for the defined benefit plans are:

	Expected 2004	2003	2002
Nexen			
Defined Benefit	6	15	2
Other	-	1	1
Total Funding Contributions	6	16	3
Syncrude			
Defined Benefit	4	2	1
Other	-	-	-
Total Funding Contributions	4	2	1

Our most recent funding valuation was prepared as of June 30, 2003. Our next funding valuation is required by June 30, 2006. Syncrude's most recent funding valuation was prepared as of January 1, 2001. Syncrude's next funding valuation is January 1, 2004.

Our total benefit payments in 2003, were $6 million (2002 - $7 million). Our share of Syncrude's total benefit payments in 2003 was $2 million (2002 - $2 million). Our estimated future payments are as follows:

	Defined Benefit		Other	
	Nexen	Syncrude	Nexen	Syncrude
2004	7	2	1	-
2005	8	2	1	-
2006	8	3	1	-
2007	9	3	1	-
2008	9	3	2	-
2009 – 2013	60	23	10	2

12. MARKETING AND OTHER

	2003	2002	2001
Marketing Revenue, Net	568	496	438
Interest	9	7	17
Foreign Exchange Gains (Losses)	6	(3)	-
Other	27	4	20
	610	504	475

For 2003, other includes $12 million of business interruption proceeds received from our insurers. The proceeds result from damage sustained in the Gulf of Mexico during tropical storm Isidore and Hurricane Lili in the third and fourth quarters of 2002.

13. INCOME TAXES

(a) Temporary Differences

	2003		2002	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Property, Plant and Equipment, Net	26	523	23	704
Tax Losses Carried Forward	69	-	226	-
Deferred Income	-	200	-	177
Recoverable Taxes	13	-	14	-
Other	-	1	-	(8)
	108	724	263	873

(b) Canadian and Foreign Income Taxes

	2003	2002	2001
Income before Income Taxes:			
From Continuing Operations			
Canadian	(173)	108	187
Foreign	967	541	529
	794	649	716
From Discontinued Operations	29	32	38
	823	681	754
Provision for Income Taxes:			
Current			
Canadian	5	4	6
Foreign	205	219	210
	210	223	216
Future			
From Continuing Operations			
Canadian	(105)	20	60
Foreign	65	(32)	7
	(40)	(12)	67
From Discontinued Operations	14	18	21
	(26)	6	88

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, the United States and Australia, and include Yemen cash taxes of $201 million (2002 - $207 million; 2001 - $191 million). Income taxes from our discontinued operations are Canadian.

(c) Reconciliation of Effective Tax Rate to the Canadian Federal Tax Rate

	2003	2002	2001
Income before Income Taxes			
From Continuing Operations	794	649	716
From Discontinued Operations	29	32	38
	823	681	754
Provision for Income Taxes Computed at the Canadian Statutory Rate	304	269	317
Add (Deduct) the Tax Effect of:			
Royalties and Rentals to Provincial Governments	51	57	66
Resource Allowance and Provincial Tax Rebates	(55)	(67)	(68)
Lower Tax Rates on Foreign Operations	(54)	(37)	(15)
Additional Canadian Tax on Canadian Resource Income	12	8	2
Federal and Provincial Capital Tax	4	4	5
Revaluation of the Future Tax Liability for the Reductions in the Statutory Rates	(76)	(1)	(5)
Other	(2)	(4)	2
Provision for Income Taxes	184	229	304

During the last three years, the federal and some provincial governments in Canada reduced statutory income tax rates. In 2003, this reduced our liability and provision for future income taxes by $76 million (2002 - $1 million; 2001 - $5 million).

(d) Available Unused Tax Losses and Tax Contingencies

At December 31, 2003, we had unused tax losses totalling $195 million (2002 - $534 million) mostly from our US operations.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some that may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an adequate provision for income taxes based on available information.

At the time of acquisition, Wascana had outstanding taxation issues in dispute from prior taxation years. Wascana disagreed with issues raised and has filed notices of objection. The value of the tax pools acquired at the time of acquisition reflected our evaluation of the potential impact of these issues.

14. CASH FLOWS

(a) Charges and credits to income not involving cash

	2003	2002	2001
Depreciation, Depletion and Amortization	1,017	685	595
Loss (Gain) on Disposition of Assets	-	8	(5)
Future Income Taxes	(40)	(12)	67
Non-Cash Items included in Discontinued Operations	35	61	56
Other	8	8	-
	1,020	750	713

(b) Changes in non-cash working capital

	2003	2002	2001
Operating Activities			
Accounts Receivable	(488)	(388)	471
Inventories and Supplies	(45)	(73)	73
Other Current Assets	(59)	(6)	(5)
Accounts Payable and Accrued Liabilities	260	404	(397)
Accrued Interest Payable	9	17	1
Dividends Payable	3	-	-
	(320)	(46)	143
Investing Activities			
Accounts Payable and Accrued Liabilities	(18)	7	(18)
Total	(338)	(39)	125

(c) Other cash flow information

	2003	2002	2001
Interest Paid	133	117	106
Income Taxes Paid	211	238	211

15. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has three operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico. Our other operations are primarily in West Africa, Australia and Colombia. Oil and gas also includes our marketing operations. Marketing sells our own crude oil and natural gas, markets third party crude oil and natural gas and engages in energy trading.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from oil sands in northern Alberta, Canada.

Chemicals: We manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine and caustic soda. We produce sodium chlorate at five facilities in Canada and one in Brazil. We produce chlorine and caustic soda at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

2003 Operating and Geographic Segments

(Cdn$ millions)

	Oil and Gas						Syncrude	Chemicals	Corporate and Other	Total
	Yemen	Canada	United States	Australia	Other Countries [1]	Marketing [2]				
Net Sales [3]	827	609	707	64	65	21	240	375 [4]	-	2,908
Marketing and Other	6	5	14	-	-	568	-	2	15 [5]	610
Gain (Loss) on Disposition of Assets	-	-	-	-	-	-	-	-	-	-
Total Revenues	833	614	721	64	65	589	240	377	15	3,518
Less: Expenses										
Operating	92	143	86	30	15	22	123	240	-	751
Transportation and Other	5	4	-	-	-	398	11	42	1	461
General and Administrative	5	27	13	-	20	43	1	21	60	190
Depreciation, Depletion and Amortization	168	490 [11]	207	22	38	15	14	46	17	1,017
Exploration	17	34	89	1	59 [6]	-	-	-	-	200
Interest	-	-	-	-	-	-	-	-	105	105
Income (Loss) from Continuing Operations before Income Taxes	546	(84)	326	11	(67)	111	91	28	(168)	794
Less: Provision for (Recovery of) Income Taxes [7]	191	(96)	115	(2)	(1)	39	25	10	(111)	170
Net Income (Loss) from Continuing Operations	355	12	211	13	(66)	72	66	18	(57)	624
Add: Net Income from Discontinued Operations	-	15 [8]	-	-	-	-	-	-	-	15
Net Income (Loss)	355	27	211	13	(66)	72	66	18	(57)	639
Identifiable Assets	574	2,136	1,420	28	165	1,518 [9]	712	471	601	7,625
Capital Expenditures										
Development and Other	219	259	249	1	24	1	195	24	29	1,001
Exploration	34	51	147	1	96	-	-	-	-	329
Proved Property Acquisitions	-	-	164 [10]	-	-	-	-	-	-	164
	253	310	560	2	120	1	195	24	29	1,494
Property, Plant and Equipment										
Cost	1,898	2,879	2,095	172	313	157	811	760	168	9,253
Less: Accumulated DD&A	1,497	1,428	854	168	198	56	141	371	71	4,784
Net Book Value [3]	401	1,451	1,241	4	115	101	670	389	97	4,469
Goodwill										
Cost	-	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	-	24	-	-	-	24
Net Book Value	-	-	-	-	-	36	-	-	-	36

Notes:

1 Includes results of operations from producing activities in Nigeria and Colombia.

2 Includes results of operations from a natural gas-fired generating facility in Alberta. In 2002, these results were included in Corporate and Other.

3 Net sales made from all segments originating in Canada. $ 1,218
Property, Plant and equipment located in Canada. $ 2,566

4 Net sales for our chemicals operations include:

Canada	$ 282
United States	13
Brazil	80
	$ 375

5 Includes interest income of $9 million and foreign exchange gains of $6 million.

6 Includes exploration activities primarily in West Africa, Colombia and Brazil.

7 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

8 In August 2003, we sold non-core conventional light oil assets in southeast Saskatchewan for net proceeds of $268 million. No gain or loss was recognized on the sale.

9 Approximately 80% of Marketing's identifiable assets are accounts receivable and inventories.

10 On March 27, 2003, we acquired the residual 40% interest in Aspen in the Gulf of Mexico for US$109 million.

11 Includes impairment charge of $269 million as discussed in Note 4.

2002 Operating and Geographic Segments

(Cdn$ millions)

	Oil and Gas						Syncrude	Chemicals	Corporate and Other [1]	Total
	Yemen	Canada	United States	Australia	Other Countries [2]	Marketing				
Net Sales [3]	789	556	296	165	78	-	245	367 [4]	10	2,506
Marketing and Other	-	2	-	-	-	496	-	2	4 [5]	504
Gain (Loss) on Disposition of Assets	-	(21) [6]	-	-	-	-	-	-	13 [7]	(8)
Total Revenues	789	537	296	165	78	496	245	369	27	3,002
Less: Expenses										
Operating	86	151	94	50	22	-	109	229	10	751
Transportation and Other	-	-	3	-	-	423	6	40	3	475
General and Administrative	4	22	11	1	19	30	1	21	43	152
Depreciation, Depletion and Amortization	149	218	133	53	46	8	13	52	13	685
Exploration	21	30	82	3	45 [8]	-	-	-	-	181
Interest	-	-	-	-	-	-	-	-	109	109
Income (Loss) from Continuing Operations before Income Taxes	529	116	(27)	58	(54)	35	116	27	(151)	649
Less: Provision for (Recovery of) Income Taxes [9]	188	41	(10)	19	(18)	12	37	9	(67)	211
Net Income (Loss) from Continuing Operations	341	75	(17)	39	(36)	23	79	18	(84)	438
Add: Net Income from Discontinued Operations	-	14 [10]	-	-	-	-	-	-	-	14
Net Income (Loss)	341	89	(17)	39	(36)	23	79	18	(84)	452
Identifiable Assets	600	2,124	1,452	63	159	811 [11]	536	538	277	6,560
Capital Expenditures										
Development and Other	209	258	541	46	23	2	141	45	97 [12]	1,362
Exploration	22	60	116	3	58	-	-	-	-	259
Proved Property Acquisitions	-	4	-	-	-	-	-	-	-	4
	231	322	657	49	81	2	141	45	97	1,625
Property, Plant and Equipment										
Cost	2,054	3,098	2,186	209	305	86	628	789	213	9,568
Less: Accumulated DD&A	1,646	1,137	959	184	198	40	139	345	57	4,705
Net Book Value [3]	408	1,961	1,227	25	107	46	489	444	156	4,863
Goodwill										
Cost	-	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	-	24	-	-	-	24
Net Book Value	-	-	-	-	-	36	-	-	-	36

Notes:

1 Includes results of operations from a natural gas-fired generating facility in Alberta.

2 Includes results of operations from producing activities in Nigeria and Colombia.

3 Net sales made from all segments originating in Canada. $ 1,162
Property, Plant and equipment located in Canada. $ 2,908

4 Net sales for our chemicals operations include:

Canada	$ 251
United States	56
Brazil	60
	$ 367

5 Includes interest income of $7 million and foreign exchange losses of $3 million.

6 On December 30, 2002, we disposed of non-operated oil and gas properties for proceeds of $14 million.

7 On January 2, 2002, we disposed of our Moose Jaw Asphalt operation for proceeds of $27 million plus working capital.

8 Includes exploration activities primarily in Nigeria, Colombia and Brazil.

9 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

10 In August 2003, we sold non-core conventional light oil assets in southeast Saskatchewan for net proceeds of $268 million. No gain or loss was recognized on the sale.

11 Approximately 87% of Marketing's identifiable assets are accounts receivable and inventories.

12 Includes $67 million related to the buy out of the lease agreement related to the construction of a natural gas-fired generating facility in Alberta.

2001 Operating and Geographic Segments

(Cdn$ millions)

	Oil and Gas						Syncrude	Chemicals	Corporate and Other [1]	Total
	Yemen	Canada	United States	Australia	Other Countries [2]	Marketing				
Net Sales [3]	711	551	358	141	61	-	225	373 [4]	77	2,497
Marketing and Other	-	10	1	-	6	438	-	3	17 [5]	475
Gain on Disposition of Assets	-	-	1	3	-	-	-	-	1	5
Total Revenues	711	561	360	144	67	438	225	376	95	2,977
Less: Expenses										
Operating	71	132	66	52	19	-	114	243	61	758
Transportation and Other	-	-	-	-	-	342	-	34	24	400
General and Administrative	3	25	8	1	21	23	1	18	36	136
Depreciation, Depletion and Amortization	111	197	116	65	31	14	12	34	15	595
Exploration	25	39	101	13	82 [6]	-	-	-	-	260
Interest	-	-	-	-	-	-	-	-	112	112
Income (Loss) from Continuing Operations before Income Taxes	501	168	69	13	(86)	59	98	47	(153)	716
Less: Provision for (Recovery of) Income Taxes [7]	185	69	27	5	(24)	26	32	16	(53)	283
Net Income (Loss) from Continuing Operations	316	99	42	8	(62)	33	66	31	(100)	433
Add: Net Income from Discontinued Operations	-	17 [8]	-	-	-	-	-	-	-	17
Net Income (Loss)	316	116	42	8	(62)	33	66	31	(100)	450
Identifiable Assets	520	2,123	880	47	179	470 [9]	399	534	173	5,325
Capital Expenditures										
Development and Other	185	367	120	(4)	23	-	60	73	47	871
Exploration	44	84	197	12	74	-	-	-	-	411
Proved Property Acquisitions	-	7	115	-	-	-	-	-	-	122
	229	458	432	8	97	-	60	73	47	1,404
Property, Plant and Equipment										
Cost	1,839	2,867	1,636	167	271	89	487	744	137	8,237
Less: Accumulated DD&A	1,491	913	848	144	166	32	127	296	50	4,067
Net Book Value [3]	348	1,954	788	23	105	57	360	448	87	4,170
Goodwill										
Cost	-	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	-	24	-	-	-	24
Net Book Value	-	-	-	-	-	36	-	-	-	36

Notes:

1 Includes results of our Moose Jaw Asphalt operation, which was disposed of on January 2, 2002.

2 Includes results of operations from producing activities in Nigeria.

3 Net sales made from all segments originating in Canada. $ 1,190
Property, Plant and equipment located in Canada. $ 2,709

4 Net sales for our chemicals operations include:

Canada	$	241
United States		90
Brazil		42
	$	373

5 Includes interest income of $17 million.

6 Includes exploration activities primarily in Nigeria, Indonesia, and Colombia.

7 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

8 In August 2003, we sold non-core conventional light oil assets in southeast Saskatchewan for net proceeds of $268 million. No gain or loss was recognized on the sale.

9 Approximately 78% of Marketing's identifiable assets are accounts receivable and inventories.

16. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

(a) Consolidated Statement of Income – US GAAP For the Three Years ended December 31, 2003

(Cdn$ millions except per share amounts)	2003	2002	2001
Revenues			
Net Sales (xi)	2,908	2,506	2,497
Marketing and Other (iii); (v); (x)	623	498	475
	3,531	3,004	2,972
Expenses			
Operating (xi)	757	751	758
Transportation and Other (i); (viii); (xi)	489	483	395
General and Administrative	190	152	136
Depreciation, Depletion and Amortization (ii); (ix)	1,130	738	641
Exploration	200	181	260
Interest (i)	169	181	182
	2,935	2,486	2,372
Income from Continuing Operations before Income Taxes	596	518	600
Provision for Income Taxes			
Current	210	223	216
Deferred (i) – (xi)	(89)	(43)	36
	121	180	252
Net Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	475	338	348
Net Income (Loss) from Discontinued Operations (ii)	(7)	14	17
Cumulative Effect of Changes in Accounting Principles, Net of Income Taxes (ix); (x)	(48)	-	-
Net Income – US GAAP [1]	420	352	365
Earnings Per Common Share ($/share)			
Basic (Note 8)			
Net Income from Continuing Operations	3.83	2.77	2.89
Net Income (Loss) from Discontinued Operations	(0.06)	0.11	0.14
Cumulative Effect of Changes in Accounting Principles	(0.38)	-	-
	3.39	2.88	3.03
Diluted (Note 8)			
Net Income from Continuing Operations	3.80	2.73	2.85
Net Income (Loss) from Discontinued Operations	(0.06)	0.11	0.14
Cumulative Effect of Changes in Accounting Principles	(0.38)	-	-
	3.36	2.84	2.99

Note:

[1] **Reconciliation of Canadian and US GAAP Net Income**

(Cdn$ millions)	2003	2002	2001
Net Income – Canadian GAAP	639	452	450
Impact of US Principles, Net of Income Taxes:			
Fair Value of Currency Swap (v)	3	(4)	-
Fair Value of Preferred Securities (x)	7	-	-
Depreciation, Depletion and Amortization (ii); (ix)	(92)	(53)	(46)
Dividends on Preferred Securities (i)	(40)	(43)	(39)
Issue Costs on Preferred Securities Redeemed (i)	(21)	-	-
Natural Gas Futures and Basis Swaps (iii)	(2)	-	-
Research and Development Costs (xi)	(4)	-	-
Loss on Disposition (ii)	(22)	-	-
Cumulative Effect of Changes in Accounting Principles (ix); (x)	(48)	-	-
Net Income – US GAAP	420	352	365

(b) Consolidated Balance Sheet – US GAAP

(Cdn$ millions, except share amounts)	December 31 **2003**	December 31 **2002**
Assets		
Current Assets		
Cash and Short-Term Investments	1,087	59
Accounts Receivable (iii)	1,423	990
Inventories and Supplies	270	256
Other	79	26
Total Current Assets	2,859	1,331
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion and Amortization of $5,330 (December 31, 2002 – $4,992) (ii); (ix); (xi)	4,583	5,064
Goodwill	36	36
Deferred Income Tax Assets	108	263
Deferred Charges and Other Assets (i); (vi)	117	70
	7,703	6,764
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-term Borrowings	-	18
Current Portion of Long-Term Debt	575	-
Accounts Payable and Accrued Liabilities (iii)	1,418	1,200
Accrued Interest Payable	44	39
Dividends Payable	12	9
Total Current Liabilities	2,049	1,266
Long-Term Debt (i); (vi); (x)	2,472	2,575
Deferred Income Tax Liabilities (i) – (xi)	676	876
Dismantlement and Site Restoration (ix)	-	191
Asset Retirement Obligation (ix)	305	-
Other Deferred Credits and Liabilities (vii)	70	44
Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2003 - 125,606,107 shares		
2002 - 122,965,830 shares	513	440
Contributed Surplus	1	-
Retained Earnings (i) – (xi)	1,660	1,280
Accumulated Other Comprehensive Income (i); (iii); (iv); (vii)	(43)	92
Total Shareholders' Equity	2,131	1,812
Commitments, Contingencies and Guarantees		
	7,703	6,764

(c) Consolidated Statement of Comprehensive Income – US GAAP For the Three Years ended December 31, 2003

(Cdn$ millions)	**2003**	**2002**	**2001**
Net Income – US GAAP	420	352	365
Other Comprehensive Income, net of income taxes:			
Translation Adjustment (i); (iv)	(127)	34	(3)
Unrealized Mark-to-Market Gain (Loss) (iii)	(7)	-	-
Minimum Unfunded Pension Liability (vii)	(1)	(2)	-
Comprehensive Income	285	384	362

(d) Consolidated Statement of Cash Flows

Under US principles, dividends on preferred securities of $64 million (2002 - $72 million; 2001 - $70 million) that are included in financing activities would be reported in operating activities.

Under US principles, geological and geophysical costs of $62 million (2002 - $80 million; 2001 - $79 million) that are included in investing activities would be reported in operating activities.

(e) Other Supplementary Information

	2003	2002	2001
Pro Forma Earnings – Fair-Value Method of Accounting for Stock Options			
Net Income – US GAAP			
As Reported	420	352	365
Plus: Fair Value of Stock Options Granted after December 31, 2002	1	-	-
Less: Fair Value of Stock Options Awarded	25	22	25
	396	330	340
Earnings per Common Share ($/share)			
Basic as Reported	3.39	2.88	3.03
Pro Forma	3.19	2.70	2.81
Diluted as Reported	3.36	2.84	2.99
Pro Forma	3.16	2.67	2.79

(f) Changes in Accounting Principles

Asset Retirement Obligations

On January 1, 2003 we adopted Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. FAS 143 requires recognition of a liability for the future retirement obligations associated with our property, plant and equipment, which includes oil and gas wells and facilities, and chemicals plants. These obligations, which generally relate to dismantlement and site restoration, are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation.

This change in accounting policy has been reported as a cumulative effect adjustment in the Consolidated Statement of Income as a loss of $37 million, net of income taxes of $25 million. Under the old accounting rules, our results would have been:

	2003
Net Income – US GAAP	
As Reported	420
Cumulative Effect of Change in Accounting Principle	37
Depreciation, Depletion, Amortization, and Accretion	10
Adjusted	467
Earnings per Common Share ($/share)	
Basic as Reported	3.39
Adjusted	3.76
Diluted as Reported	3.36
Adjusted	3.73

Had FAS 143 been applied during all periods presented, our asset retirement obligation, including current obligations of $18 million at December 31, 2003 and $14 million at December 31, 2002, would have been reported as follows:

	As Reported	Pro-forma
January 1, 2002	182	364
December 31, 2002	205	390
December 31, 2003	323	323

The change in our asset retirement obligation since the beginning of the year is as follows:

	2003
Asset Retirement Obligation at January 1	390
Obligation Incurred	6
Abandonment Expenditures	(20)
Property Disposition	(27)
Accretion	22
Revision in Estimate	(19)
Effect of Foreign Exchange	(29)
Asset Retirement Obligation at December 31	323

We own interests in several assets for which the fair value of the asset retirement obligation cannot be reasonably determined because the assets currently have an indeterminate life. These assets include our interests in one gas plant and our interest in Syncrude's upgrader and sulfur pile. The asset retirement obligation for these assets will be recorded in the first year in which the lives of the assets are determinable.

Had FAS 143 been applied during all periods presented, our December 31, 2002 and 2001 results would have been reported as follows:

	2002	**2001**
Net Income – US GAAP		
As Reported	352	365
Depreciation, Depletion, Amortization, and Accretion	2	1
Adjusted	350	364
Earnings per Common Share ($/share)		
Basic as Reported	2.88	3.03
Adjusted	2.86	3.02
Diluted as Reported	2.84	2.99
Adjusted	2.82	2.98

Fair Value of Instruments with Equity and Liability Components

In May 2003, FASB issued Statement No. 150, *Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity* that establishes standards for classifying and measuring certain financial instruments with characteristics of both liabilities and equity. Certain financial instruments, including our preferred securities, must be recorded at fair value with changes in fair value recognized through net income. The change in fair value of our preferred securities up to June 30, 2003 increased the carrying value of our long-term debt by $16 million and was recognized as a loss of $11 million, net of income taxes of $5 million. This was reported as a cumulative effect of a change in an accounting principle. Since adopting this change in accounting principle at the beginning of the third quarter, the fair value of our preferred securities has decreased by $12 million and this gain was included in marketing and other. The tax effect of $5 million on this gain increased our deferred income tax provision.

***Notes to the Consolidated US GAAP Financial Statements*:**

i. Under US principles, the preferred and subordinated securities are classified as long-term debt rather than shareholders' equity. The pre-tax dividends on the preferred securities are included in interest expense, and the related income tax is included in the provision for income taxes in the Consolidated Statement of Income. The related pre-tax issue costs are included in deferred charges and other assets rather than as an after-tax charge to retained earnings. The foreign-currency translation gains or losses are included in accumulated other comprehensive income (AOCI) as the preferred securities have been designated as a hedge of our foreign net investments. The pre-tax dividends are included in operating activities in the Consolidated Statement of Cash Flows.

   On December 15, 2003, we redeemed our US$259 million preferred securities. Under Canadian principles, a foreign exchange gain of $31 million, net of income tax, was recognized in retained earnings. Under US principles, the preferred securities have been revalued each reporting period and the gains and losses have been included in AOCI. Issue costs of $27 million have been expensed to other expense.

ii. Under US principles, the liability method of accounting for income taxes was adopted in 1993. In Canada, the liability method was adopted in 2000. In 1997, we acquired certain oil and gas assets and the amount paid for these assets differed from the tax basis acquired. Under US principles, this difference was recorded as a deferred tax liability with an increase to property, plant and equipment rather than a charge to retained earnings. As a result, depreciation expense under US principles is higher.

   During the third quarter of 2003, some of these assets were sold as described in Note 9. With the carrying value of these assets higher under US GAAP, the sale resulted in a loss on disposition of $22 million, net of income taxes of $10 million. This loss is included in the income (loss) from discontinued operations on the Consolidated Statement of Income.

   Included in depreciation, depletion and amortization expense for 2003 is an impairment charge of $315 million ($205 million after tax) as described in Note 4. The amount is higher under US GAAP as we have higher US GAAP carrying values for the assets impaired resulting from differences in adopting the liability method of accounting for income taxes as previously described.

iii. Under US principles, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met.

   Cash flow hedges: Changes in the fair value of derivatives that are designated as cash flow hedges are deferred and recognized in earnings in the same period as the hedged item. The effective portion of the change is deferred in other comprehensive income with any ineffectiveness of the hedge recognized immediately on the income statement.

   Included in accounts payable at December 31, 2003 is a $3 million loss (December 31, 2002 - $nil) on the forward contracts we used to hedge the future sale of a portion of our production from the Aspen field as described in Note 5. The contracts limit our exposure to fluctuations in commodity prices by fixing our cash flow from the hedged sale production. We deferred this loss ($2 million, net of income tax) in AOCI until the underlying production is sold. All of these deferred losses will be reclassified to net sales in the next twelve months as the production is sold.

   Included in accounts payable at December 31, 2003 are losses of $11 million (December 31, 2002 - $nil) on the futures and basis swap contracts we used to hedge the future sale of our gas inventory as described in Note 5. The effective portion of these losses is deferred to AOCI until the underlying gas inventory is sold ($5 million after taxes of $3 million). The ineffective portion of the losses is recognized immediately in marketing and other ($2 million after taxes of $1 million). All of the deferred losses in AOCI will be reclassified to marketing and other in the next twelve months as the gas inventory is sold.

   Fair value hedges: Both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value. The change in the fair value of both are reflected in earnings. Included in both accounts receivable and accounts payable at December 31, 2003 is $nil (December 31, 2002 - $2 million) related to fair value hedges. The hedges converted fixed prices for physical delivery of natural gas into a floating price through a fixed to floating swap. The contracts expired in November 2003. The impact on earnings was immaterial.

iv. Under US principles, exchange gains and losses arising from the translation of our net investment in self-sustaining foreign operations are included in comprehensive income. Additionally, exchange gains and losses, net of income taxes, from the translation of our US-dollar long-term debt designated as a hedge of our foreign net investment are included in comprehensive income. Cumulative amounts are included in AOCI in the Consolidated Balance Sheet.

v. Under US principles, a derivative and a cash instrument cannot be designated in combination as a net investment hedge. The $4 million gain in fair value and foreign exchange gains and losses during the year (2002 – loss of $5 million; 2001 - $nil) on our US$37 million currency swap were included in marketing and other.

vi. Under US principles, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred charges and other assets.

vii. Under US principles, the amount by which our accrued pension cost is less than the unfunded accumulated benefit obligation is included in comprehensive income and accrued pension liabilities. This amount was $2 million at December 31, 2003 (December 31, 2002 - $4 million).

viii. Under US principles, gains and losses on the disposition of assets are shown as other expense.

ix. On January 1, 2003, we adopted Financial Accounting Standards Board (FASB) Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143) as described under Changes in Accounting Principles. Under Canadian GAAP, we will adopt similar standards effective January 1, 2004.

x. On July 1, 2003, we adopted FASB Statement No. 150, "Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity" as described under Changes in Accounting Principles.

xi. Under Canadian principles, we defer certain development costs and all pre-operating revenues and costs to PP&E. Under US principles, these costs are charged to earnings as incurred. In 2003, we recognized $6 million of pre-operating expenses in earnings rather than defer them.

xii. On January 1, 2002, we adopted FASB Statement No. 142, which eliminated goodwill amortization and instead required annual impairment testing. No goodwill impairment writedowns were required during the year. Our unamortized goodwill at January 1, 2002 was $36 million. The following shows the adjusted net income and earnings per common share had the new standard been applied in 2001:

	2003	**2002**	**2001**
Net Income			
As Reported	420	352	365
Add: Goodwill Amortization	-	-	6
Adjusted	420	352	371
Earnings Per Common Share ($/share)			
Basic as Reported	3.39	2.88	3.03
Adjusted	3.39	2.88	3.07
Diluted as Reported	3.36	2.84	2.99
Adjusted	3.36	2.84	3.04

NEW ACCOUNTING PRONOUNCEMENTS

The following standards issued by the FASB do not impact us:

- Statement No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities,* effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003.
- Interpretation No. 46, *Consolidation of Variable Interest Entities*, effective for financial statements issued after January 31, 2003.

SUPPLEMENTARY FINANCIAL INFORMATION (Unaudited)

Quarterly Financial Data in Accordance with Canadian and US GAAP

(Cdn$ millions)

	Quarter Ended							
	March 31		June 30		September 30		December 31	
	2003	2002	2003	2002	2003	2002	2003	2002
Net Sales [1]	806	517	726	621	716	687	660	681
Operating Profit								
Oil and Gas [1, 2, 3]	379	91	261	180	260	210	(57)	176
Syncrude [4]	28	20	18	9	32	47	13	40
Chemicals	3	3	9	4	12	11	4	9
	410	114	288	193	304	268	(40)	225
Interest and Other Corporate [5]	45	24	27	43	35	36	61	48
Income Tax Expense [6]	121	28	3	49	91	82	(45)	52
Net Income from Continuing Operations in accordance with Canadian GAAP	244	62	258	101	178	150	(56)	125
US GAAP Adjustment	(25)	(23)	(99)	(22)	(11)	(23)	(14)	(32)
Net Income from Continuing Operations in accordance with US GAAP	219	39	159	79	167	127	(70)	93
Net Income in accordance with Canadian GAAP	251	65	263	101	181	157	(56)	129
US GAAP Adjustment	(62)	(23)	(99)	(22)	(44)	(23)	(14)	(32)
Net Income in accordance with US GAAP	189	42	164	79	137	134	(70)	97
Net Income from Continuing Operations per Common Share ($/share)								
Canadian GAAP	1.89	0.42	2.01	0.74	1.36	1.13	(0.52)	0.94
US GAAP	1.78	0.32	1.29	0.65	1.35	1.03	(0.56)	0.77
Net Income per Common Share ($/share)								
Canadian GAAP	1.95	0.44	2.05	0.74	1.38	1.20	(0.52)	0.96
US GAAP	1.53	0.35	1.33	0.65	1.11	1.09	(0.56)	0.79
Dividends Declared [7]	0.075	0.075	0.075	0.075	0.075	0.075	0.100	0.075
Common Share Prices ($/share)								
Toronto Stock Exchange								
High	34.85	39.75	35.59	42.50	39.68	42.18	47.08	37.78
Low	29.30	29.70	28.26	37.20	33.02	34.34	36.65	31.00
New York Stock Exchange								
High (US$)	22.55	25.11	26.31	28.04	29.00	27.71	36.47	23.85
Low (US$)	19.89	18.57	19.75	23.30	24.03	21.70	27.32	19.79

Notes:

1 Excludes results of the non-core conventional light oil assets in southeast Saskatchewan that were sold. These results are shown as discontinued operations (see Note 9 of the Consolidated Financial Statements).

2 A loss of $21 million was recorded on the disposition of non-operated oil and gas properties during the fourth quarter of 2002.

3 Includes impairment charge of $269 million (see Note 4 of the Consolidated Financial Statements).

4 Plant turnarounds and unplanned coker maintenance in the second quarter of 2002 and the fourth quarter of 2003 increased operating costs and temporarily reduced production volumes.

5 A gain of $13 million was recorded on the disposition of our Moose Jaw Asphalt operation during the first quarter of 2002.

6 Canadian GAAP net income includes a reduction in tax rates for Canadian resource activities in the second quarter of 2003. This reduction was recognized in the fourth quarter of 2003 for US GAAP.

7 In February 2004, the Board of Directors declared a regular quarterly dividend of $0.10 per common share, payable April 1, 2004, to shareholders of record on March 10, 2004.

8 At December 31, 2003, there were 1,420 registered holders of common shares and 125,606,107 common shares outstanding.

Oil and Gas Netbacks before Royalties

(Sales prices, per unit costs and netbacks are calculated using our working interest production before royalties.)

($/boe)	2003						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	39.45	32.99	42.88	43.14	38.22	43.36	38.63
Royalties and other	(19.98)	(7.53)	(5.91)	(3.44)	(5.69)	(0.48)	(12.14)
Operating expense	(2.16)	(6.00)	(4.49)	(18.60)	(7.47)	(21.96)	(5.19)
In-country taxes	(4.73)	-	-	-	-	-	(2.06)
Cash netback	12.58	19.46	32.48	21.10	25.06	20.92	19.24

($/boe)	2002						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	38.80	27.90	34.21	40.30	38.96	40.89	35.14
Royalties and other	(20.45)	(6.53)	(5.82)	(7.88)	(16.48)	(0.36)	(12.56)
Operating expense	(1.95)	(5.70)	(9.09)	(9.76)	(6.21)	(18.10)	(5.42)
In-country taxes	(4.81)	-	-	-	-	-	(2.10)
Cash netback	11.59	15.67	19.30	22.66	16.27	22.43	15.06

($/boe)	2001						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	35.05	26.60	39.42	38.71	37.37	39.90	33.28
Royalties and other	(18.66)	(6.26)	(6.85)	(2.36)	(7.07)	(1.72)	(11.40)
Operating expense	(1.62)	(4.87)	(6.01)	(13.50)	(8.07)	(19.43)	(4.88)
In-country taxes	(4.40)	-	-	-	-	-	(1.95)
Cash netback	10.37	15.47	26.56	22.85	22.23	18.75	15.05

Oil and Gas Netbacks after Royalties

(Sales prices, per unit costs and netbacks are calculated using our working interest production after royalties.)

($/boe)	2003						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	39.45	32.99	42.88	43.14	38.22	43.36	38.63
Operating expense	(4.37)	(7.76)	(5.19)	(20.21)	(9.01)	(22.18)	(7.56)
In-country taxes	(9.58)	-	-	-	-	-	(3.00)
Cash netback	25.50	25.23	37.69	22.93	29.21	21.18	28.07

($/boe)	2002						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	38.80	27.90	34.21	40.30	38.96	40.89	35.14
Operating expense	(4.13)	(7.45)	(10.87)	(12.14)	(10.69)	(18.21)	(8.26)
In-country taxes	(10.17)	-	-	-	-	-	(3.20)
Cash netback	24.50	20.45	23.34	28.16	28.27	22.68	23.68

($/boe)	2001						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	35.05	26.60	39.42	38.71	37.35	39.90	33.28
Operating expense	(3.47)	(5.82)	(7.31)	(14.38)	(9.94)	(20.29)	(7.10)
In-country taxes	(9.41)	-	-	-	-	-	(2.86)
Cash netback	22.17	20.78	32.11	24.33	27.41	19.61	23.32

OIL AND GAS PRODUCING ACTIVITIES (Unaudited)

The following oil and gas information is provided in accordance with the US Financial Accounting Standards Board Statement No. 69 "Disclosures about Oil and Gas Producing Activities".

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and at least 80% of the reserves have been assessed by independent qualified reserves consultants.

Estimates of conventional crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year-end. See Critical Accounting Estimates and Business Risk Management sections in Item 7 for a discussion of reserves estimation and the related risks.

Conventional oil and Syncrude reserves are in mmbbls and natural gas reserves in bcf	Syncrude [3]	Total Conventional Oil	Total Conventional Gas	Yemen [1] Oil	Canada Oil	Canada Gas	United States Oil	United States Gas	Other Countries [2] Oil
Proved Developed and Undeveloped Reserves [4]									
December 31, 2000	203	300	673	107	166	509	18	164	9
Revisions of Previous Estimates	-	1	-	7	(14)	(1)	2	1	6
Purchases of Reserves in Place	-	2	64	-	2	3	-	61	-
Sales of Reserves In Place	-	-	(2)	-	-	(2)	-	-	-
Extensions and Discoveries	34	53	146	17	21	91	11	55	4
Production	(6)	(47)	(90)	(20)	(18)	(54)	(3)	(36)	(6)
December 31, 2001	231	309	791	111	157	546	28	245	13
Revisions of Previous Estimates	(12)	(6)	(10)	(14)	7	(6)	1	(4)	-
Purchases of Reserves in Place	-	-	1	-	-	1	-	-	-
Sales of Reserves in Place	-	(6)	(1)	-	(2)	(1)	-	-	(4)
Extensions and Discoveries	13	72	103	23	10	31	32	72	7
Production	(6)	(45)	(81)	(20)	(16)	(47)	(3)	(34)	(6)
December 31, 2002	226	324	803	100	156	524	58	279	10
Revisions of Previous Estimates	5	(31)	(99)	(5)	(28)	(88)	(2)	(11)	4
Purchases of Reserves in Place	-	19	21	-	-	-	19	21	-
Sales of Reserves in Place	-	(24)	(7)	-	(24)	(6)	-	(1)	-
Extensions and Discoveries	22	48	33	36	10	20	1	13	1
Production	(5)	(47)	(90)	(21)	(13)	(45)	(9)	(45)	(4)
December 31, 2003	248	289	661	110	101	405	67	256	11
Proved Developed Reserves [5]									
December 31, 2001	212	223	676	70	126	505	18	171	9
December 31, 2002	196	246	702	61	131	487	46	215	8
December 31, 2003	192	216	576	63	91	367	54	209	8

Notes:

1 Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents their royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves include our share of future cost recovery and profit oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) since the barrels necessary to achieve cost recovery change with prevailing oil prices.

2 Represents reserves in Australia, Nigeria and Colombia.

3 US Securities and Exchange Commission regulations define these reserves as mining-related and not part of conventional oil and gas reserves. For management purposes, we view these reserves and their development as integral to our oil and gas operations. These reserves are not considered in the standardized measure of discounted future net cash flows, which follows. In 2002, Syncrude moved to generic royalty terms that provide for a royalty of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. Under this royalty regime, reported reserves will increase as oil prices decrease (and vice versa) since the barrels necessary to recover costs change with prevailing oil prices.

4 "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation test.

5 "Proved developed" oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

B. Capitalized Costs

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated Depreciation, Depletion and Amortization	Capitalized Costs
December 31, 2003				
Yemen	1,881	17	1,497	401
Canada	3,271	129	1,863	1,537
United States	2,034	123	892	1,265
Other Countries	454	85	420	119
Syncrude	819	-	144	675
Total	8,459	354	4,816	3,997
December 31, 2002				
Yemen	2,024	30	1,646	408
Canada	2,882	216	1,137	1,961
United States	2,061	125	959	1,227
Other Countries	460	54	382	132
Syncrude	628	-	139	489
Total	8,055	425	4,263	4,217
December 31, 2001				
Yemen	1,808	31	1,491	348
Canada	2,750	117	913	1,954
United States	1,522	114	848	788
Other Countries	434	4	310	128
Syncrude	487	-	127	360
Total	7,001	266	3,689	3,578

C. Costs Incurred

(Cdn$ millions)	Total		Conventional Oil and Gas			
	Conventional Oil and Gas	Syncrude	Yemen	Canada	United States	Other Countries
Year Ended December 31, 2003						
Property Acquisition Costs						
Proved	164	-	-	-	164	-
Unproved	38	-	-	-	38	-
Exploration Costs	291	-	34	51	109	97
Development Costs	752	195	219	259	249	25
Asset Retirement Costs	185	8	-	69	62	54
	1,430	203	253	379	622	176
Year Ended December 31, 2002						
Property Acquisition Costs						
Proved	4	-	-	4	-	-
Unproved	31	-	-	-	31	-
Exploration Costs	228	-	22	60	85	61
Development Costs	1,077	141	209	258	541	69
	1,340	141	231	322	657	130
Year Ended December 31, 2001						
Property Acquisition Costs						
Proved	122	-	-	7	115	-
Unproved	37	-	19	-	18	-
Exploration Costs	374	-	25	84	179	86
Development Costs	691	60	185	367	120	19
	1,224	60	229	458	432	105

D. Results of Operations for Producing Activities

(Cdn$ millions)	Total		Conventional Oil and Gas			
	Conventional Oil and Gas	Syncrude	Yemen	Canada	United States	Other Countries
Year Ended December 31, 2003						
Net Sales	2,338	240	827	675	707	129
Production Costs	382	123	92	159	86	45
Exploration Expense	201	-	17	35	89	60
Depreciation, Depletion and Amortization	1,057	15	168	613	207	69
Other Expenses (Income)	87	12	4	64	(1)	20
	611	90	546	(196)	326	(65)
Income Tax Provision (Recovery)	188	25	191	(112)	115	(6)
Results of Operations	423	65	355	(84)	211	(59)
Year Ended December 31, 2002						
Net Sales	1,984	245	789	656	296	243
Production Costs	428	115	86	176	94	72
Exploration Expense	189	-	21	38	82	48
Depreciation, Depletion and Amortization	634	13	149	253	133	99
Other Expenses (Income)	79	1	4	41	14	20
	654	116	529	148	(27)	4
Income Tax Provision (Recovery)	238	37	188	59	(10)	1
Results of Operations	416	79	341	89	(17)	3
Year Ended December 31, 2001						
Net Sales	1,918	225	711	647	358	202
Production Costs	363	114	71	155	66	71
Exploration Expense	265	-	25	44	101	95
Depreciation, Depletion and Amortization	550	12	111	227	116	96
Other Expenses (Income)	37	1	3	15	6	13
	703	98	501	206	69	(73)
Income Tax Provision (Recovery)	283	32	185	90	27	(19)
Results of Operations	420	66	316	116	42	(54)

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved conventional oil and gas reserves (excluding Syncrude). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory-tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	Other Countries
December 31, 2003					
Future Cash Inflows	14,660	4,416	5,319	4,470	455
Future Production Costs	3,651	868	1,980	666	137
Future Development Costs	788	412	102	249	25
Future Dismantlement and Site Restoration Costs, Net	309	-	112	137	60
Future Income Tax	2,152	574	656	854	68
Future Net Cash Flows	7,760	2,562	2,469	2,564	165
10% Discount Factor	2,243	620	879	691	53
Standardized Measure	5,517	1,942	1,590	1,873	112
December 31, 2002					
Future Cash Inflows	18,687	4,662	9,067	4,516	442
Future Production Costs	3,943	881	2,375	535	152
Future Development Costs	722	296	169	228	29
Future Dismantlement and Site Restoration Costs, Net	227	-	24	150	53
Future Income Tax	3,650	790	1,976	863	21
Future Net Cash Flows	10,145	2,695	4,523	2,740	187
10% Discount Factor	3,776	819	2,081	818	58
Standardized Measure	6,369	1,876	2,442	1,922	129
December 31, 2001					
Future Cash Inflows	10,337	3,068	5,034	1,880	355
Future Production Costs	3,104	597	1,694	633	180
Future Development Costs	790	283	202	231	74
Future Dismantlement and Site Restoration Costs, Net	229	-	47	136	46
Future Income Tax	1,520	661	751	96	12
Future Net Cash Flows	4,694	1,527	2,340	784	43
10% Discount Factor	1,607	385	1,004	202	16
Standardized Measure	3,087	1,142	1,336	582	27

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	**2003**	**2002**	**2001**
Beginning of Year	6,369	3,087	4,991
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(2,298)	(1,158)	(2,012)
Net Changes in Prices and Production Costs Related to Future Production	(1,249)	3,083	(2,871)
Extensions, Discoveries and Improved Recovery, Less Related Costs	740	1,929	691
Changes in Estimated Future Development and Dismantlement Costs	(279)	(103)	(382)
Previous Estimated Future Development and Dismantlement Costs Incurred during the Period	456	425	443
Revisions of Previous Quantity Estimates	(291)	267	(33)
Accretion of Discount	884	409	736
Purchases of Reserves in Place	354	2	161
Sales of Reserves in Place	(252)	(109)	(1)
Net Change in Income Taxes	1,083	(1,463)	1,364
End of Year	5,517	6,369	3,087

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

On June 3, 2002, the Canadian firm of Deloitte & Touche LLP (Deloitte Canada) completed a transaction with the Canadian firm of Arthur Andersen LLP (Andersen Canada) to integrate partners and staff of Andersen Canada into Deloitte Canada. On July 11, 2002, our Board accepted the resignation of Andersen Canada and appointed Deloitte Canada as our auditors until the 2003 Annual General Meeting (AGM). Deloitte Canada was re-appointed as our auditors at the 2003 AGM until the next AGM in 2004.

There were no disagreements with accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-d-15(e)) as of the end of the period covered by this report. They concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were adequate and effective in ensuring that material information relating to the Company and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this report was being prepared. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and in reaching a reasonable level of assurance, management necessarily is required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures.

CHANGES IN INTERNAL CONTROLS

We have continually had in place systems relating to internal control over financial reporting. There has not been any change in the Company's internal control over financial reporting during the fourth quarter of 2003 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART III

Item 10. Directors and Executive Officers of the Registrant

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. On January 5, 2004, the directors determined that, until changed, there will be 11 directors.

Our By-Laws provide that directors will be elected at the annual general meeting of shareholders (AGM) each year and will hold office until their successors are elected. All of our current directors were elected at the last AGM except Mr. Newell, who was appointed by the Board on January 5, 2004.

This table shows each director's principal occupation or employment during the past five years and any other directorships they held in public companies as at February 12, 2004. The following directors are management nominees for election to the Board.

Name (Age)	Principal Occupation and Other Directorships	Director Since
Charles W. Fischer (53)	President and Chief Executive Officer (CEO) of Nexen. Formerly, Executive Vice President and Chief Operating Officer (COO).	2000
Dennis G. Flanagan [1,2] (64)	Retired oil executive. Director of NAL Oil & Gas Trust.	2000
David A. Hentschel [1] (70)	Retired oil executive. Formerly, Chairman and CEO of Occidental Oil and Gas Corporation. A director of Cimarex Energy Co.	1985
S. Barry Jackson [1] (51)	Retired oil executive. Formerly, President and CEO of Crestar Energy Inc. Director and Executive Chairman of Resolute Energy Inc. and a director of TransCanada Corporation, and TransCanada Pipelines Limited and Deer Creek Energy Limited.	2001
Kevin J. Jenkins [1,2] (47)	Managing Director of TriWest Capital Management Corp. Formerly, President and CEO and a director of The Westaim Corporation.	1996
Eric P. Newell, O.C. (59)	Retired Chairman and CEO of Syncrude Canada Ltd. Director of Canfor Corporation.	2004
Thomas C. O'Neill [1,2] (58)	Retired Chairman of PwC Consulting. Formerly, CEO of PwC Consulting. Prior to that, COO of PricewaterhouseCoopers LLP, Global. Prior to that, CEO of PricewaterhouseCoopers LLP, Canada and, prior to that, Chairman and CEO of Price Waterhouse Canada. Director of BCE Inc., Loblaw Companies Limited, Dofasco Inc.	2002
Francis M. Saville, Q.C. (65)	Counsel to Fraser Milner Casgrain LLP, Barristers and Solicitors. Formerly, Senior Partner of Fraser Milner Casgrain LLP, Barristers and Solicitors. Director of Mullen Transportation Inc.	1994
Richard M. Thomson, O.C. [1,2] (70)	Retired banking executive. Director of the Toronto-Dominion Bank, Prudential Financial Inc., INCO Limited, The Thomson Corporation, Trizec Properties Inc. and Stuart Energy Systems Corporation.	1997
John M. Willson (64)	Retired Vice Chairman of Placer Dome Inc. Formerly, CEO of Placer Dome Inc., and, prior to that, President and CEO of Placer Dome Inc. Director of Finning International Inc. and PanAmerican Silver Corp.	1996
Victor J. Zaleschuk (60)	Retired President and CEO of Nexen. Director of Cameco Corporation and Agrium Inc.	1997

Notes:

[1] Members of Nexen's Audit and Conduct Review Committee. All members of the Committee are independent pursuant to Nexen's Categorical Standards for Director Independence which meet or exceed all requirements under applicable regulations of the US Securities and Exchange Commission, the *Sarbanes-Oxley Act of 2002* and the New York Stock Exchange.

[2] Financial Experts on Nexen's Audit and Conduct Review Committee.

EXECUTIVE OFFICERS

The Board of Directors determines the term of office for each executive officer. Below are Nexen's officers. Prior offices and non-executive positions are set out for officers who have not held their current executive positions with Nexen for more than 5 years. Start dates are indicated for officer positions with Nexen.

Officer (Age)	Current and Past Position(s) with Nexen	Effective Date of Current Position	Executive Officer Since
Charles W. Fischer (53)	President and Chief Executive Officer and a Director Formerly: Executive Vice President and Chief Operating Officer since May 14, 1997	June 1, 2001	1994
Marvin F. Romanow (49)	Executive Vice President and Chief Financial Officer Formerly: Senior Vice President, Finance since February 19, 1999 Vice President, Finance and Chief Financial Officer since February 27, 1998	June 1, 2001	1997
Laurence Murphy [1] (53)	Senior Vice President, International Oil and Gas	January 1, 1999	1998
John B. McWilliams, Q.C. [1] (56)	Senior Vice President, General Counsel and Secretary	May 11, 1993	1987
Douglas B. Otten [1] (60)	Senior Vice President, United States Oil and Gas	May 12, 1998	1990
Thomas A. Sugalski [1] (60)	Senior Vice President, Chemicals	May 10, 1994	1988
Roger D. Thomas (51)	Senior Vice President, Canadian Oil and Gas Formerly: Vice President, Canada since May 12, 1998	February 19, 1999	1998
Nancy F. Foster (44)	Vice President, Human Resources and Corporate Services Formerly: Division Vice President, Finance – Canadian Oil and Gas General Manager, Human Resources	July 11, 2000	2000
Gary H. Nieuwenburg (45)	Vice President, Synthetic Crude Formerly: Vice President, Corporate Planning and Business Development since February 16, 2001 Division Vice President, Exploration and Production – Canadian Oil and Gas	July 11, 2002	2001
Kevin J. Reinhart (45)	Vice President, Corporate Planning and Business Development Formerly: Treasurer since October 20, 1998	July 11, 2002	1994
Una M. Power [2] (39)	Treasurer Formerly: Controller and Director, Corporate Insurance since May 2, 2002 Controller and Director, Risk Management since December 1, 1998	July 11, 2002	1998
Michael J. Harris (40)	Controller Formerly: Manager, Corporate Finance – Treasury Division Vice President, Finance – International General Manager – New Ventures Finance	December 10, 2002	2002

Notes:

[1] Officer has held the same executive position with Nexen for more than 5 years.

[2] Ms. Power concurrently maintained her position as Controller until December 10, 2002.

Ethics Policy

Under Nexen's Ethics Policy, all directors, officers and employees must demonstrate a commitment to ethical business practices and behaviour in all business relationships, both within and outside of Nexen. An employee, regardless of his or her position, is not permitted to commit an unethical, dishonest or illegal act or to instruct other employees to do so. Our Ethics Policy has been adopted as a code of ethics applicable to our principal executive officer, principal financial officer and principal accounting officer or controller. Any waivers of or changes to the Ethics Policy must be approved by the Board of Directors and appropriately disclosed.

Our Ethics Policy is available on our internet website at www.nexeninc.com, under "Our Commitment", and it is our intention to provide disclosure in this manner.

Item 11. Executive Compensation

SUMMARY COMPENSATION

This table summarizes the compensation earned by Nexen's Chief Executive Officer and the four highest compensated officers other than the Chief Executive Officer.

		Annual Compensation			Long-Term Compensation	
					Awards	
Name and Principal Position	Year	Salary ($)	Bonus [1] ($)	Other Annual Compensation ($)	Securities Underlying Options Granted (#)	All Other Compensation ($)
Charles W. Fischer	2003	725,000	600,000	-	100,000	43,500 [2]
President and Chief	2002	637,500	300,000	-	100,000	38,250 [2]
Executive Officer	2001	540,667	400,000	-	105,000	32,440 [2]
Marvin F. Romanow	2003	440,500	267,000	-	55,000	26,430 [2]
Executive Vice President	2002	418,000	310,000	-	50,000	25,080 [2]
and Chief Financial Officer	2001	376,333	225,000	-	60,000	22,582 [2]
Douglas B. Otten	2003	416,152	226,170	-	37,000	24,969 [2] / 60,221 [3]
Senior Vice President,	2002	485,873	125,886	-	35,000	29,156 [2] / 63,005 [3]
United States Oil and Gas	2001	456,783	405,685	-	28,000	27,407 [2] / 79,874 [3]
Thomas A. Sugalski	2003	384,439	156,380	-	30,000	23,066 [2]/53,395 [3]
Senior Vice President,	2002	449,993	118,019	-	30,000	26,999 [2]/ 60,889 [3]
Chemicals	2001	422,908	232,240	417,695 [4]	25,000	25,374 [2]/ 76,059 [3]
Laurence Murphy	2003	366,500	196,000	-	37,000	21,990 [2]
Senior Vice President,	2002	346,000	90,000	-	35,000	20,760 [2]
International Oil and Gas	2001	329,250	180,000	-	28,000	19,758 [2]

Notes:

1 Bonuses for a year are determined based on performance during the year and are paid to the employee in the following year. Bonuses are paid pursuant to the Incentive Compensation Plan. The bonuses indicated were the payments made in the year shown.

2 Contributions to the Employee Savings Plan.

3 Nexen contributed to a Qualified Defined Contribution Plan and a Restoration Plan with Nexen Petroleum U.S.A. Inc. for Mr. Otten and Mr. Sugalski.

4 Represents a special settlement payment for termination from Occidental Petroleum Corporation Non-Qualified Executive Benefit Plans.

Stock Options

Pursuant to Nexen's Stock Option Plan, the Board, on the recommendation of the Compensation and Human Resources Committee, may grant stock options to Nexen officers and employees. Nexen does not receive any consideration when options are granted. The option exercise price is the market price of Nexen's common shares on the Toronto Stock Exchange for Canadian based employees or the New York Stock Exchange for US based employees, when the option is granted.

The Board determines the term of each option, to a maximum of ten years, and the vesting schedule. Options granted before February 2001 have a term of ten years; 20% of the grant vests after six months and then 20% more vests each year for four years on the anniversary of the grant. Options granted after February 2001 have a term of five years and vest one-third each year over three years. Generally, if a change of control event occurs (as defined in the Stock Option Plan), all issued but unvested options will become vested.

Option Grants During 2003

Name	Securities Underlying Options Granted (#)	% of Total Options/Stock Appreciation Rights Granted to Employees in Financial Year	Exercise or Base Price [1] ($/Security) [2]	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
					5% ($)	10% ($)
Charles W. Fischer	100,000	3.5	43.50	December 9, 2008	1,201,825	2,655,719
Marvin F. Romanow	55,000	1.9	43.50	December 9, 2008	661,004	1,460,645
Douglas B. Otten	37,000	1.3	33.38 (US$)	December 9, 2008	417,161	921,816
Thomas A. Sugalski	30,000	1.1	33.38 (US$)	December 9, 2008	357,566	790,128
Laurence Murphy	37,000	1.3	43.50	December 9, 2008	444,675	982,616

Notes:
1 Equal to the market value of securities underlying options on the date of grant.
2 All values in Canadian dollars unless otherwise noted.

Options Exercised During 2003 and Financial Year-end Option Values

Name	Securities Acquired on Exercise (#)	Value Realized [1] ($) [2]	Number of Securities Underlying Unexercised Options at Financial Year-end (#) Exercisable / Unexercisable	Value of Unexercised In-The-Money-Options at Financial Year-end ($) [2] Exercisable / Unexercisable
Charles W. Fisher	-	-	424,750 / 214,650	8,267,883 / 1,871,016
Marvin F. Romanow	-	-	199,200 / 117,800	3,012,334 / 920,106
Douglas B. Otten	71,329	1,240,978	146,131 / 75,340	2,370,825 / 742,312
Thomas A. Sugalski	51,000	578,078	95,950 / 65,050	1,545,036 / 1,088,696
Laurence Murphy	-	-	170,660 / 77,340	3,199,051 / 658,699

Notes:
1 Equals market price at the time of the exercise minus exercise price.
2 All values in Canadian dollars.

Benefit Plans

All named executive officers, except Mr. Sugalski and Mr. Otten, are members of Nexen's Defined Benefit Pension Plan and of the Executive Benefit Plan.

Defined Benefit Pension Plan

Under this plan, participants must contribute 3% of their regular gross earnings, up to an allowable maximum, to the pension plan. Upon retirement, they receive a benefit equal to 1.7% of their average earnings for the 36 highest paid consecutive months during the ten years before retirement, multiplied by the number of years of credited service. The plan is integrated with the Canada Pension Plan (CPP) in order to provide a maximum offset of one-half of the CPP benefit.

Pension benefits earned prior to January 1, 1993 will be indexed on an ad hoc basis. Pension benefits earned after December 31, 1992 will be indexed at an amount equal to the greater of:

- 75% of the increase in the Canadian Consumer Price Index less 1% to a maximum of 5%; and
- 25% of the increase in the Canadian Consumer Price Index.

Nexen contributed $14 million to the Defined Benefit Pension Plan in 2003.

Executive Benefit Plan

The plan provides supplemental benefits to the extent that benefits under the pension plan are limited by statutory guidelines.

Estimated Pension Benefit

This table shows the estimated annual pension an executive officer who retired on December 31, 2003 would receive, assuming that the amount in the Summary Compensation Table above is the officer's final average salary. It includes benefits from both the Defined Benefit Pension Plan and Executive Benefit Plan and assumes a retirement age of 65. The normal form of benefit paid from this plan is joint life with 66 ⅔% to the surviving spouse.

	Years of Service						
REMUNERATION	5	10	15	20	25	30	35
$500,000	$41,681	$83,363	$125,044	$166,726	$208,407	$250,089	$291,770
$550,000	$45,931	$91,863	$137,794	$183,726	$229,657	$275,589	$321,520
$600,000	$50,181	$100,363	$150,544	$200,726	$250,907	$301,089	$351,270
$650,000	$54,431	$108,863	$163,294	$217,726	$272,157	$326,589	$318,020
$700,000	$58,681	$117,363	$176,044	$234,726	$293,407	$352,089	$410,770
$750,000	$62,931	$125,863	$188,794	$251,726	$314,657	$377,589	$440,520
$800,000	$67,181	$134,363	$201,544	$268,726	$335,907	$403,089	$470,270
$850,000	$71,431	$142,863	$214,294	$285,726	$357,157	$428,589	$500,020
$900,000	$75,681	$151,363	$227,044	$302,726	$378,407	$454,089	$529,770
$950,000	$79,931	$159,863	$239,794	$319,726	$399,657	$479,589	$559,520
$1,000,000	$84,181	$168,363	$252,544	$336,726	$420,907	$505,089	$589,270
$1,050,000	$88,431	$176,863	$265,294	$353,726	$442,157	$530,589	$619,020
$1,100,000	$92,681	$185,363	$278,044	$370,726	$463,407	$556,089	$648,770
$1,150,000	$96,931	$193,863	$290,794	$387,726	$484,657	$581,589	$678,520
$1,200,000	$101,181	$202,363	$303,544	$404,726	$505,907	$607,089	$708,270
$1,250,000	$105,431	$210,863	$316,294	$421,726	$527,157	$632,589	$738,020
$1,300,000	$109,681	$219,363	$329,044	$438,726	$548,407	$658,089	$767,770
$1,350,000	$113,931	$227,863	$341,794	$455,726	$569,657	$683,589	$797,520

An executive officer's average earnings for purposes of the plan includes stated salary and the lesser of the eligible target incentive bonus or the actual incentive bonus paid.

Messrs. Fischer, Romanow and Murphy have 19.58, 16.50 and 17.67 years of credited service, respectively.

Employee Savings Plan

The Summary Compensation Table includes Nexen's contribution to the savings plan made on behalf of executive officers. All regular employees may participate in our Employee Savings Plan. Through payroll deductions, employees may contribute any percentage of their regular earnings to purchase Nexen common shares and/or mutual fund units. Nexen matches employee contributions to a maximum of 6% of regular earnings. The extent of matching is based on the investment option selected and the employee's length of participation in the plan. The full amount of Nexen's contribution is invested in common shares and is fully vested immediately. Employee and employer contributions may be allocated to registered or non-registered accounts.

Change of Control Agreements

Nexen has entered into Change of Control Agreements with Messrs. Fischer, Romanow, Otten, Sugalski, Murphy and other key executives. The agreements were effective October 1999, amended December 2000 and amended and restated December 2001. The agreements recognize that these executives are critical to Nexen's ongoing business. They recognize the need to retain the executives, protect them from employment interruption due to a change in control and treat them in a fair and equitable manner, consistent with industry standards.

For the purposes of these agreements, a change of control includes any acquisition of common shares or other securities that carry the right to cast more than 35% of the votes attaching to all common shares and, in general, any event, transaction or arrangement which results in a person or group exercising effective control of Nexen.

If the named executives are terminated following a change in control, they will be entitled to receive salary and benefits for a specified severance period. For Mr. Fischer and Mr. Romanow, the severance period is 36 months. They may also terminate their employment on a voluntary basis following a change of control with severance periods of 36 and 30 months, respectively. For Messrs. Otten, Sugalski and Murphy, the severance period is 30 months.

Director Compensation

All directors who are not employees are paid:

- an annual retainer of $28,100 for services on the Board and $1,800 for each Board meeting attended; and
- an annual retainer of $9,100 for service on each Committee and $1,800 for each Committee meeting attended.

The Chair of the Board was paid an annual retainer of $108,000 until the end of 2003. The Chair of each Committee is paid an additional annual retainer of $5,300. In October 2003, all director compensation was reviewed and the annual retainer for the Chair of the Board was increased to $150,000.

In 2001, a Deferred Share Unit (DSU) plan was approved as an alternative form of compensation for non-employee directors. Under the plan, eligible directors may elect annually to receive all or part of their fees in the form of DSUs, rather than cash. A DSU is a bookkeeping entry which tracks the value of one Nexen common share. DSUs are not paid out until the director leaves the Board, providing an ongoing equity stake in Nexen during the director's term of service. Payments of DSUs may be made in cash or in Nexen common shares purchased on the open market at the time of payment.

In 2003, the Board adopted a policy setting out that non-executive directors would no longer be granted stock options. Non-executive directors will not be eligible to receive stock options under the proposed amendments to the Stock Option Plan. Deferred Stock Units have since been employed as an alternate method of performance-based compensation. In December 2003, all directors who were not employees of Nexen were granted 2,100 DSUs, except for the Chair of the Board, who was granted 3,200 DSUs.

Directors' and Officers' Liability Insurance

Nexen maintains a directors' and officers' liability insurance policy for the benefit of our directors and officers. The policy provides coverage for costs incurred to defend and settle claims against its directors and officers to an annual limit of US$125 million with a US$1 million deductible per occurrence. The cost of coverage for 2003 was approximately US$0.6 million.

Share Ownership Guidelines for Directors

The Board believes it is important that directors demonstrate their commitment through share ownership. The Board has approved guidelines setting out that directors are expected to own or control at least 3,000 shares, to be accumulated over three years. Specific arrangements may be made when a qualified candidate might be precluded from serving by these guidelines. The guidelines are reviewed by the Board from time to time.

REPORT OF THE COMPENSATION AND HUMAN RESOURCES COMMITTEE

The Compensation and Human Resources Committee administers Nexen's Incentive Compensation Plan, Stock Option Plan, Stock Appreciation Rights Plan and Pension Plan. It reviews and approves executive management's recommendations for the annual salaries, bonuses and grants of stock options and stock appreciation rights. The Committee reports to the Board and the Board gives final approval to compensation matters. The Committee evaluates the performance of the CEO and recommends his compensation which is approved by the independent directors of the Board.

Policies of the Committee

Nexen is committed to pay for performance, improved shareholder returns and external competitiveness. These principles are factored into the design, development and administration of our compensation programs, as directed by the Committee.

The Committee believes maximizing shareholder return is the most important measure of success. At the operational level, this translates primarily into net income, cash flow and net asset value growth. At the corporate headquarters level, this results from successful implementation of necessary strategic change. The Committee recognizes the need to attract and retain a stable and focused leadership capable of managing Nexen's operations, finances and assets. As appropriate, the Committee rewards exceptional individual contributions with highly competitive compensation.

To ensure competitiveness, Nexen hires various independent compensation consulting firms to compare our executive compensation practices to our peers, primarily major Canadian oil and gas and, where relevant, chemical and marketing companies.

Our compensation program has three components: salary, annual cash incentives and long-term incentives.

Base Salaries

To determine base salaries, Nexen maintains a framework of job levels based on internal comparability and external market data. The Committee's goal is to provide total cash compensation for our top performing employees between the 50th and 75th percentile as compared to our peers.

Annual Incentives

The Board approves any annual cash incentives awarded under the Annual Incentive Plan. The Committee determines the total amount of cash available for annual incentive awards by evaluating a combination of financial and non-financial criteria, including net income, operating cash flow and specific strategic goals outlined in a balanced scorecard. The primary indicators, net income and cash flow, are commonly used metrics in our industry and each represents one-quarter of the overall assessment. The qualitative assessment of the balanced scorecard performance indicators provides a comprehensive evaluation and accounts for the remaining one-half of the overall performance assessment. Individual target award levels increase in relation to job responsibilities so that the ratio of at-risk versus fixed compensation is greater for higher levels of management. Individual awards are intended to reflect a combination of overall Nexen, personal and business unit performance, along with market competitiveness.

The incentive plan is reviewed annually to ensure the plan continues to attract, motivate, reward and retain the high performing and high potential employees needed to achieve Nexen's business objectives, while reflecting long-term fiscal responsibility to our shareholders.

Stock and Long-Term Incentives

The Board believes that employees should have a stake in Nexen's future and that their interest should be aligned with the interests of our shareholders. To this end, Nexen's contributions to employee savings plans are made in Nexen common shares. In addition, the Committee selects those directors, officers and employees whose decisions and actions can most directly impact business results to participate in the Stock Option Plan and the Stock Appreciation Rights Plan.

Under these plans, participating directors, officers and employees receive grants of stock options or stock appreciation rights as a long-term incentive to increase shareholder value. The grants have a five-year term and vest one-third each year for the first three years of the term on the anniversary date of the grant. Awards of stock options and stock appreciation rights are supplementary to the Annual Incentive Plan and are intended to increase the variable pay component for senior management.

The Stock Appreciation Rights Plan was introduced in 2001. For employees at or below mid-level department managers, these rights are typically granted instead of stock options.

To determine the number of stock options available for distribution, we consider market information on stock options and the impact of the program on shareholders. The focus in 2003 was on providing differentiated awards based on performance, potential and retention risk.

The total options granted and shares reserved for issuance under our stock-based compensation arrangements will not, at any time, exceed 10% of our total outstanding shares.

Nexen maintains share ownership guidelines for executive officers as a way of aligning executive and shareholder interests. The Chief Executive Officer, Chief Financial Officer and other executive officers are expected to own shares representing three, two and one times annual base salary, respectively. In determining compliance with the guidelines, share ownership includes the net value of exercisable options, flow-through shares, shares purchased and held within the Nexen Savings Plan and any other personal holdings.

President and Chief Executive Officer Compensation

Competitive compensation information for our President and Chief Executive Officer is determined based on assessments conducted by independent compensation consulting firms which compare similar positions in oil and gas and in the broader industrial sector. Target total cash compensation (base salary plus incentive bonus) is at the low end of the range of the oil and gas comparator group.

The award to Mr. Fischer under the Annual Incentive Plan, is a percentage of his target bonus based on the composite performance rating approved by the Board which takes into account the three components of the plan, the first two being the targets for net income and cash flow and the last one being a qualitative assessment. The qualitative assessment includes a scorecard of targets for growth and operating performance, such as net asset value growth, cost management, safety record, production volumes and reserve growth, among others. An important measure in the scorecard is the extent to which the operations were conducted in an environmentally safe and socially responsible manner.

Annual salary increases for Mr. Fischer are based on his performance against key objectives using a broad selection of criteria including the following:

- overall achievement of corporate/financial performance;
- achievement of strategic objectives;
- progress on long-term objectives;
- team building and succession planning;
- visionary leadership; and
- social responsibility.

Based on the Board assessment of Mr. Fischer's achievement of objectives in 2002, his base salary was increased to $750,000 in 2003 and he was awarded a bonus of $600,000 under the Annual Incentive Plan.

Mr. Fischer was also granted options to purchase 100,000 shares at an exercise price of $43.50 under the Nexen Stock Option Plan. Awards under the Stock Option Plan are a direct link to the stock performance and form a part of the competitive overall compensation package.

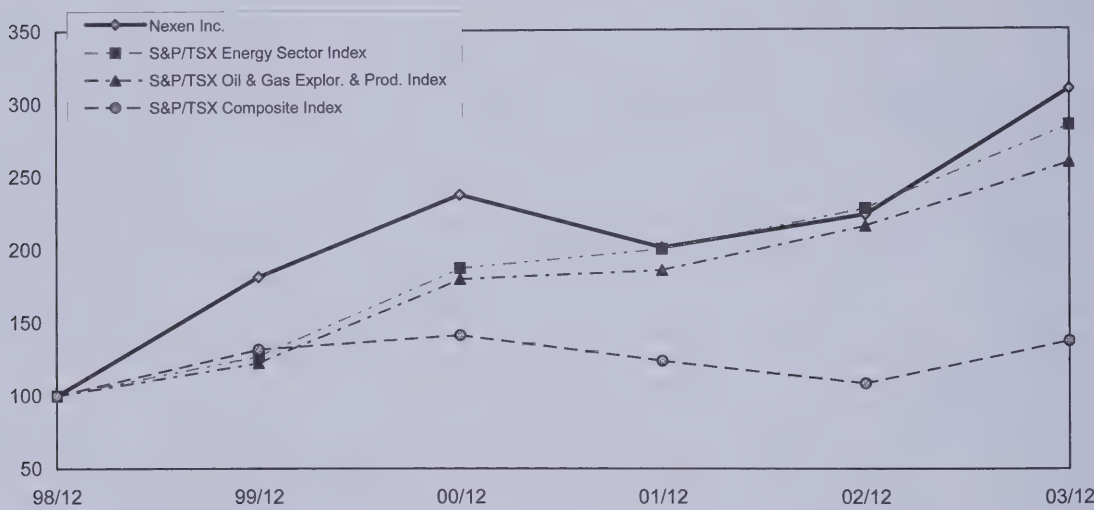
Submitted on behalf of the Compensation and Human Resources Committee:

John Willson, Chair
Dave Hentschel
Barry Jackson
Francis Saville, Q.C.
Dick Thomson, O.C.
Vic Zaleschuk

Share Performance Graph

The following graph shows changes in the past five year period, ending December 31, 2003 in the value of $100 invested in our common shares, compared to the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index and the S&P/TSX Oil & Gas Exploration & Production Index as at December 31, 2003. Our common shares are included in each of these indices.

TOTAL RETURN INDEX VALUES



	1998/12	1999/12	2000/12	2001/12	2002/12	2003/12
Nexen Inc.	100.00	181.55	237.58	201.38	223.69	309.16
S&P/TSX Energy Sector Index	100.00	126.86	187.36	200.31	227.84	284.72
S&P/TSX Oil & Gas Explor. & Prod. Index	100.00	122.38	179.94	185.75	215.78	259.26
S&P/TSX Composite Index	100.00	131.71	141.47	123.69	108.30	137.25

Assuming an investment of $100 and the reinvestment of dividends

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Nexen's common shares are the only class of voting securities. Based on information known to Nexen, the following table shows each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of Nexen's voting securities at December 31, 2003.

Name and Address of Beneficial Owner	# of Shares Beneficially Owned	% of Shares
Jarislowsky Fraser Limited [1] Suite 2005, 1010 Sherbrooke Street West Montreal, Quebec, Canada, H3A 2R7	21,565,906	17.2
Ontario Teachers' Pension Plan Board [2] 5650 Yonge Street Toronto, Ontario, Canada, M2M 4H5	19,533,318	15.6
Capital Research and Management Co. [3] 333 South Hope Street Los Angeles, California, U.S.A., 90071-1447	7,080,010	5.6

Notes:

[1] The beneficial owner has sole voting power over 19,262,406 shares, shared voting power over 2,303,500 shares; and sole power to dispose of all of the shares.

[2] The beneficial owner has sole voting and power to dispose all of the shares.

[3] The beneficial owner has sole power to dispose all of the shares and disclaims beneficial ownership pursuant to Rule 13d-4.

SECURITY OWNERSHIP OF MANAGEMENT

At December 31, 2003, the following directors, certain executive officers, and all directors and executive officers as a group beneficially owned the following Nexen common shares:

Name of Beneficial Owner	Number of Shares [1]	Exercisable Stock Options [2]
Charles W. Fischer	28,096	424,750
Dennis G. Flanagan	3,001	18,225
David A. Hentschel	5,615	28,225
S. Barry Jackson	6,000	6,225
Kevin J. Jenkins	3,044	28,225
Eric P. Newell, O.C.	Nil	Nil
Thomas C. O'Neill	4,000	1,870
Francis M. Saville, Q.C.	3,151	28,225
Richard M. Thomson, O.C.	23,001	42,388
John M. Willson	5,001	28,225
Victor J. Zaleschuk	15,612	297,025
Laurence Murphy	19,480	170,660
Douglas B. Otten	17,200	146,131
Marvin F. Romanow	19,627	199,200
Thomas A. Sugalski	9,663	95,950
All directors and executive officers as a group (22 persons)	212,435	2,005,874

Notes:

[1] The number of shares held and stock options exercisable by each beneficial owner represents less than 1% of the shares outstanding.

[2] Includes all stock options exercisable within 60 days of December 31, 2003.

Under the terms of our stock option plan, the Board of Directors may grant stock options to officers and employees and, when previously allowed for, to directors. Nexen does not receive any consideration when options are granted.

Equity Compensation Plan Information:

	Number of securities to be issued upon exercise of outstanding options (a)	Weighted-average exercise price of outstanding options (b)	Number of securities remaining available for future issuance under equity compensation plans (c)
Equity compensation plans approved by shareholders	9,203,121	$34.00	9,787,833

Item 13. Certain Relationships and Related Transactions

CERTAIN BUSINESS RELATIONSHIPS

Mr. Saville, a director, was a senior partner of Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta until the end of January 2004. Beginning on February 1, 2004, he is counsel with the firm. FMC has rendered legal services to Nexen during each of the last five years. Mr. Saville is independent pursuant to the Categorical Standards for Director Independence (Categorical Standards) adopted by Nexen.

Item 14. Principal Accounting Fees and Services

AUDIT FEES

Fees billed by Deloitte & Touche LLP were:

- $596,000 for 2003 ($550,000 for 2002) for the audit of the Consolidated Financial Statements included in our Annual Report on Form 10-K.
- $42,000 for the 2003 first, second and third quarter reviews ($31,000 for the 2002 second and third quarter reviews) for the Consolidated Financial Statements included on Form 10-Qs.

Fees billed by Arthur Andersen LLP during 2002 were $13,000 for the 2002 first quarter review of the Consolidated Financial Statements included on our form 10-Q.

AUDIT-RELATED FEES

Fees billed by Deloitte & Touche LLP, were:

- $322,000 for 2003 ($231,500 for 2002) for the annual audits of our subsidiary financial statements and employee benefit plans.
- $87,000 for 2003 ($4,000 for 2002) for comfort letters to commissions.

Fees billed by Arthur Andersen LLP during 2002 were $88,300 for comfort letters to commissions.

TAX FEES

Fees billed by Deloitte & Touche LLP, were $160,000 for 2003 ($72,550 for 2002) for tax return preparation assistance and tax-related consultation. Fees billed by Arthur Andersen LLP during 2002 were $106,601 for tax return preparation assistance and tax-related consultation.

ALL OTHER FEES

No other fees were billed by Deloitte & Touche LLP during 2003. Fees billed by Arthur Andersen LLP during 2002 were $62,900 for assisting the internal audit group with its evaluation of the implementation of an enterprise-wide resource system.

AUDIT COMMITTEE APPROVAL

Before Deloitte & Touche LLP is engaged by Nexen or our subsidiaries to render audit or non-audit services, the engagement is approved by Nexen's Audit Committee. All audit-related and tax services provided by Deloitte & Touche LLP after May, 6, 2003 were approved by our Audit Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

FINANCIAL STATEMENTS AND SCHEDULES

We refer you to the Index to Financial Statements and Related Information under Item 8 of this report where these documents are listed.

Schedules and separate financial statements of subsidiaries are omitted because they are not required or applicable, or the required information is shown in the Consolidated Financial Statements or notes.

EXHIBITS

Exhibits filed as part of this report are listed below. Certain exhibits have been previously filed with the Commission and are incorporated in this Form 10-K by reference. Instruments defining the rights of holders of debt securities that do not exceed 10% of Nexen's consolidated assets have not been included. A copy of such instruments will be furnished to the Commission upon request.

3.5 Restated Certificate of Incorporation of the Registrant dated June 5, 1995, and Restated Articles of Incorporation (filed as Exhibit 3.5 to Form 10-K for the year ended December 31, 1995, filed by the Registrant).

3.6 Certificate of Amendment of the Articles of the Registrant dated May 9, 1996 (filed as Exhibit 3.6 to Form 10-K for the year ended December 31, 1996, filed by the Registrant).

3.7 Certificate of Amendment and Articles of Amendment of the Registrant dated November 2, 2000, with respect to the name change to Nexen Inc. (filed as Exhibit 3.7 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

3.8 By-Law No. 1 of the Registrant enacted February 15, 2002, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 2 to Form 8A/A dated August 20, 2002, filed by the Registrant).

3.9 By-Law No. 2 of the Registrant enacted December 9, 2003, being a by-law relating generally to the transaction of the business and affairs of the Registrant.

4.29 Acquisition Agreement between the Registrant, Occidental Petroleum Corporation and Ontario Teachers' Pension Plan Board, dated March 1, 2000, (filed as Exhibit 4.29 to Form 10-K for the year ended December 31, 1999, filed by the Registrant).

4.32 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated November 17, 2000, amending the amount of the facility to $400 million and providing for various conforming covenant amendments to the Loan Agreement dated April 14, 1997 (as restated) (filed as Exhibit 4.32 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

4.33 Restated Loan Agreement of April 14, 1997, between the Registrant, Toronto Dominion Bank, as Agent, and the Lenders dated October 16, 2000, reducing the amount of the facility to $975 million and splitting the loan into 364 day (40%) and six-year term (60%) portions, and other various amendments (filed as Exhibit 4.33 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

4.36 First Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Banks, as Agent, and the Lenders, dated July 31, 2001 (filed as Exhibit 4.36 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

4.37 First Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated August 1, 2001 (filed as Exhibit 4.37 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

4.38 Second Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Banks, as Agent, and the Lenders, dated July 30, 2002 (filed as Exhibit 4.38 to Form 10-K for the year ended December 31, 2002, filed by the Registrant).

4.39 Second Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 31, 2002 (filed as Exhibit 4.39 to Form 10-K for the year ended December 31, 2002, filed by the Registrant).

4.40 Amended and Restated Shareholder Rights Plan Agreement dated May 2, 2002 between the Corporation and CIBC Mellon Trust Company, as Rights Agent, which includes the Form of Rights Certificate as Exhibit A (filed as Exhibit 3 to Form 8-A/A dated August 20, 2002, filed by the Registrant).

4.42 Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company providing for the issue of debt securities from time to time.

4.43 First Supplemental Indenture dated April 28, 1998 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US $200 million, 7.40% notes due 2028.

4.44 Third Amending Agreement dated July 29, 2003 to the October 16, 2000 Restated Loan Agreement of April 14, 1997 between the Registrant, the Toronto Dominion Banks, as Agent, and the Lenders.

4.45 Third Amending Agreement dated July 29, 2003 to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders.

4.46 Third Supplemental Indenture dated March 11, 2002 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of $500 million, 7.85% notes due 2032.

4.47 Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of subordinated notes from time to time.

4.48 Officer's Certificate dated November 4, 2003 pursuant to the Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issuance of US $460 million, 7.35% subordinated notes due 2043.

4.49 Fourth Amending Agreement dated November 4, 2003 to the October 16, 2003 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Banks, as Agent, and the Lenders.

4.50 Fourth Amending Agreement dated November 4, 2003 to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders.

4.51 Fourth Supplemental Indenture dated November 20, 2003 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US $500 million, 5.05% notes due 2013.

10.40 Amended and Restated Change of Control Agreements with Executive Officers dated during December, 2001 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

10.41 Indemnification Agreements made between the Registrant and its directors and officers during 2002 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2002, filed by the Registrant).

10.42 Indemnification Agreement made between the Registrant and one of its directors, Eric P. Newell, as of January 5, 2004.

11.2 Statement regarding the Computation of Per Share Earnings for the three years ended December 31, 2003.

16.1 Letter re change in certifying accountant (filed as Exhibit 16.1 to Form 8-K filed July 17, 2002 by the Registrant).

21.0 Subsidiaries of the Registrant.

23.0 Consent of Independent Chartered Accountants.

31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of periodic report by Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of periodic report by Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.1 Opinion of Internal Qualified Reserves Evaluator on National Instrument 51-101 Form F2 as required by certain Canadian securities regulatory authorities.

REPORTS ON FORM 8-K

During the quarter ended December 31, 2003, we filed or furnished the following report on Form 8-K:

- Current report on Form 8-K dated October 16, 2003, to furnish our press release announcing our 2003 third quarterly results.

Up until the filing of this Form 10-K, during 2004, we filed or furnished the following reports on Forms 8-K:

- Current report on Form 8-K dated February 5, 2004, to file our press release announcing our reserves as at December 31, 2003.
- Current report on Form 8-K dated February 13, 2004, to furnish our press release announcing our 2003 annual results.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 20, 2004.

NEXEN INC.

By: /s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2004.

/s/ Dennis G. Flanagan
Dennis G. Flanagan, Director

/s/ David A. Hentschel
David A. Hentschel, Director

/s/ S. Barry Jackson
S. Barry Jackson, Director

/s/ Kevin J. Jenkins
Kevin J. Jenkins, Director

/s/ Eric P. Newell
Eric P. Newell, Director

/s/ Thomas C. O'Neill
Thomas C. O'Neill, Director

/s/ Francis M. Saville
Francis M. Saville, Director

/s/ Richard M. Thomson
Richard M. Thomson, Director

/s/ John M. Willson
John M. Willson, Director

/s/ Victor J. Zaleschuk
Victor J. Zaleschuk, Director

/s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Michael J. Harris
Michael J. Harris
Controller
(Principal Accounting Officer)

/s/ John B. McWilliams
John B. McWilliams
Senior Vice President, General Counsel
and Secretary

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Vice President, Corporate Planning
and Business Development

EXHIBIT 31.1

CERTIFICATIONS

I, Charles W. Fischer, President and Chief Executive Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-1(e)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is likely to materially affect, the registrant's internal control over financial reporting; and;
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2004

/s/ Charles W. Fischer
Charles W. Fischer
President, and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATIONS

I, Marvin F. Romanow, Executive Vice-President and Chief Financial Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is likely to materially affect, the registrant's internal control over financial reporting; and;
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2004

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President,
and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF PERIODIC REPORT

I, Charles W. Fischer, President and Chief Executive Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 20, 2004

/s/ Charles W. Fischer
Charles W. Fischer
President, and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

CERTIFICATION OF PERIODIC REPORT

I, Marvin F. Romanow, Executive Vice President and Chief Financial Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 20, 2004

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President,
and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Growing Value

PERFORMANCE REVIEW (unaudited)

(dollar amounts in millions except as stated)	**2003**	2002	2001	2000	1999
Highlights					
Net Sales	**$ 2,908**	$ 2,506	$ 2,497	$ 1,533	$ 1,411
Cash Flow from Operations	**$ 1,859**	$ 1,383	$ 1,423	$ 1,569	$ 780
Per Common Share [1]	**$ 14.50**	$ 10.71	$ 11.20	$ 12.01	$ 5.19
Net Income	**$ 639**	$ 452	$ 450	$ 602	$ 100
Per Common Share [1]	**$ 4.84**	$ 3.34	$ 3.40	$ 4.52	$ 0.46
Capital Expenditures	**$ 1,494**	$ 1,625	$ 1,404	$ 915	$ 612
Acquisitions	**$ –**	$ –	$ –	$ 39	$ 91
Dispositions	**$ 293**	$ 49	$ 5	$ 42	$ 85
Operations					
Production					
Production before Royalties (mboe) [2]	**269**	269	268	256	239
Production after Royalties (mboe) [2]	**185**	176	184	171	163
Proved Reserves [3]					
Crude Oil and NGLs (mmbbls)	**682**	713	687	675	658
Natural Gas (mmboe) [2]	**129**	158	155	136	121
Total (mmboe) [2]	**811**	871	842	811	779
F&D Costs [4,5]					
Annual after Revisions ($/boe)	**$ 29.34**	$ 11.15	$ 9.81	$ 6.59	$ 3.50
Annual before Revisions ($/boe)	**$ 11.64**	$ 12.41	$ 9.24	$ 10.76	$ 8.98
3-year after Revisions ($/boe)	**$ 13.35**	$ 9.21	$ 6.27	$ 4.88	$ 5.19
5-year after Revisions ($/boe)	**$ 9.13**	$ 6.86	$ 6.24	$ 5.71	$ 5.48
Reserve Replacement after Revisions [4,5]					
Annual Costs ($/boe)	**$ 29.92**	$ 11.64	$ 9.80	$ 6.32	$ 3.23
Percent of Annual Production	**40**	128	132	134	174
Financial Position					
Working Capital	**$ 1,399**	$ 69	$ 24	$ 179	$ –
Property, Plant and Equipment, Net	**$ 4,469**	$ 4,863	$ 4,170	$ 3,540	$ 3,375
Total Assets	**$ 7,625**	$ 6,560	$ 5,325	$ 5,551	$ 4,105
Net Debt [6]	**$ 1,377**	$ 1,775	$ 1,460	$ 1,344	$ 1,308
Long-Term Debt	**$ 2,776**	$ 1,844	$ 1,484	$ 1,523	$ 1,308
Shareholders' Equity	**$ 2,418**	$ 2,348	$ 1,904	$ 1,460	$ 1,798
Shares and Dividends					
Common Shares Outstanding (millions)	**125.6**	123.0	121.2	119.9	138.1
Number of Common Shareholders	**1,420**	1,372	1,375	1,394	1,397
Closing Common Share Price (TSX)	**$ 46.92**	$ 34.25	$ 31.08	$ 37.00	$ 28.50
Dividends Declared per Common Share	**$ 0.33**	$ 0.30	$ 0.30	$ 0.30	$ 0.30

Notes:

1 Per share data is reported after dividends on preferred securities.
2 Natural gas is converted at 6 mcf per boe.
3 Reserves are Nexen's working interest before royalties, using year-end prices. For Nexen's reserves after royalties, using year-end prices, please refer to the Supplementary Financial Information in our Form 10-K on page 101.
4 F&D Cost is defined as oil and gas exploration and development capital expenditures divided by total proved reserve additions, excluding acquisitions and dispositions. Reserve replacement cost includes acquisitions and dispositions.
5 Based on proved reserves before royalties, at year-end prices.
6 Net Debt is defined as long-term debt less working capital.

For more historical information, view our Statistical Supplement under the Investor Centre at www.nexeninc.com
or contact Investor Relations: 403-699-5273 or investor_relations@nexeninc.com

Strong Operating Results

PERFORMANCE REVIEW (unaudited)

Cash Flow from Operations [1] ($ millions)	2003	2002	2001	2000	1999
Oil and Gas					
Yemen [2]	**$ 530**	$ 492	$ 445	$ 480	$ 318
Canada	**490**	460	477	544	252
United States	**623**	190	285	321	147
Australia	**34**	114	88	138	–
Other Countries	**30**	37	33	40	34
Marketing	**126**	45	71	36	19
Syncrude	**105**	129	110	102	86
	1,938	1,467	1,509	1,661	856
Chemicals	**74**	79	83	80	49
	2,012	1,546	1,592	1,741	905
Interest and Other Corporate Items	**(144)**	(147)	(144)	(147)	(111)
Income Taxes [3]	**(9)**	(16)	(25)	(25)	(14)
	$ 1,859	$ 1,383	$ 1,423	$ 1,569	$ 780

Oil and Gas Cash Netback [4] ($/boe)	2003	2002	2001	2000	1999
Yemen	**12.58**	11.59	10.37	11.67	8.13
Canada	**19.46**	15.67	15.47	19.05	9.93
United States	**32.48**	19.30	26.56	29.73	13.94
Australia	**21.10**	22.66	22.85	34.13	–
Syncrude	**20.92**	22.43	18.75	18.73	15.05
Company-Wide Oil and Gas	**19.24**	15.06	15.05	17.82	10.06

Notes:

1 Defined as cash generated from operating activities before changes in non-cash working capital.

2 After in-country cash taxes of $201 million for the year ended December 31, 2003 (2002—$207 million, 2001—$191 million, 2000—$217 million, 1999—$129 million).

3 Excludes in-country cash taxes in Yemen.

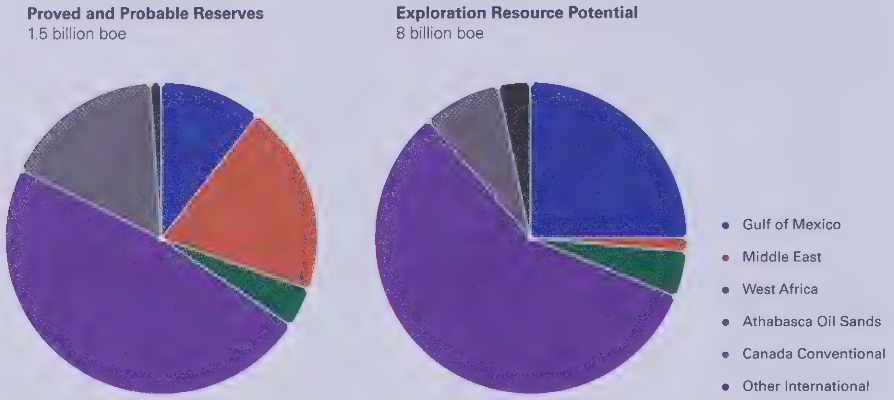
4 Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen. Calculation details can be found in the Statistical Supplement on our website. Please visit www.nexeninc.com under Investor Centre.

Solid Production After Royalties

PERFORMANCE REVIEW (unaudited)

	2003	2002	2001	2000	1999
Production before Royalties					
Crude Oil and NGLs (mbbls/d)					
Yemen	**116.8**	118.0	118.3	111.9	107.5
Canada	**46.3**	56.3	58.0	53.9	48.3
United States	**28.3**	9.9	10.0	11.1	10.3
Australia	**6.1**	12.8	10.2	12.0	0.1
Other Countries	**5.4**	8.9	6.2	6.4	10.6
Syncrude	**15.3**	16.6	16.1	14.7	16.1
	218.2	222.5	218.8	210.0	192.9
Natural Gas (mmcf/d)					
Canada	**158**	167	174	161	161
United States	**145**	112	121	113	117
	303	279	295	274	278
Total Gross Production (mboe/d)	**269**	269	268	256	239
Production after Royalties					
Crude Oil and NGLs (mbbls/d)					
Yemen	**57.5**	55.8	55.5	50.7	51.9
Canada	**35.4**	43.4	48.3	44.0	39.1
United States	**25.0**	8.2	8.3	9.3	8.6
Australia	**5.6**	10.3	9.6	12.0	–
Other Countries	**4.6**	5.2	5.3	5.4	8.4
Syncrude	**15.2**	16.5	15.5	12.1	15.8
	143.3	139.4	142.5	133.5	123.8
Natural Gas (mmcf/d)					
Canada	**125**	128	147	135	137
United States	**122**	93	99	92	95
	247	221	246	227	232
Total Net Production (mboe/d)	**185**	176	184	171	163
Chemicals Production (thousand short tons/year)					
Sodium Chlorate	**450**	451	457	462	404
Chlor-alkali	**443**	410	383	395	330
Average Sales Price before Royalties					
Crude Oil and NGLs ($/bbl)					
WTI (US$/bbl)	**$ 31.04**	$ 26.09	$ 25.97	$ 30.21	$ 19.24
Yemen	**39.45**	38.80	35.05	40.53	26.36
Canada	**32.37**	31.13	24.86	33.49	20.53
United States	**37.68**	38.88	38.35	44.18	26.51
Australia	**43.14**	40.30	38.71	41.05	–
Other Countries	**38.22**	38.96	37.37	40.12	23.30
Syncrude	**43.36**	40.89	39.90	44.84	28.12
Natural Gas ($/mcf)					
Canada	**$ 5.64**	$ 3.57	$ 5.02	$ 4.38	$ 2.46
United States	**8.16**	5.29	6.66	6.90	3.45

We're adding high-value reserves in basins with significant long-term growth potential.



In 2003, we added proved reserves of 111 million boe, before revisions, replacing 113% of our 2003 production, at finding and development costs of $11.64 per boe. New proved reserves were added in the U.S. Gulf of Mexico, Yemen, Syncrude and Canada. On a proved-plus-probable basis before revisions, we replaced almost 500% of our production, adding significant probable reserves for our Long Lake Synthetic Crude Oil Project in Canada and discoveries in Yemen and offshore West Africa. Our proved and probable reserves totalled 1.5 billion boe at December 31, 2003.

Following our annual detailed evaluation of our reserves, we reduced our proved reserve estimate by 67 million boe and recorded a non-cash, after-tax impairment charge of $175 million in 2003. Most of the revisions occurred in our conventional reserves in Canada. Our total revisions represent 8% of our company-wide proved reserves and have no impact on our 2004 production.

After revisions, our company-wide cost to find and develop proved reserves was $29.34 per boe in 2003, and our reserve replacement cost was $29.92 per boe. With 200 million barrels of new proved reserves recorded at Long Lake in 2004, we expect our 2004 F&D costs to improve significantly. More importantly, given the nature of our multi-year projects, it's more appropriate to look at our costs over longer time periods to minimize the timing impact of our reserve additions. Over the last five years, our reserve replacement cost after revisions has averaged $9.06 per boe.

As we continue transitioning 4 growth in 4 key basins, our opportunity inventory totals eight billion boe of resource potential, with half of that captured in our long-life bitumen resource in the Athabasca oil sands.

Proved and Probable Reserves

Our long-term practice has been to internally evaluate 100% of our reserves and to have at least 80% of our proved reserves audited by independent qualified reserve consultants each year. Our reserves are also reviewed and approved by our Board of Directors and the Reserves Review Committee of the Board. Our proved reserves are estimated according to U.S. Securities and Exchange Commission guidelines based on year-end constant prices.

PROVED AND PROBABLE RESERVE RECONCILIATION [1,2]

	Yemen	Canada		United States		Other International	Synthetic	Syncrude	Total
mmboe	Oil	Oil	Gas	Oil	Gas	Oil	Oil	Oil	mmboe
Proved Reserves									
December 31, 2002	183	189	103	65	55	10	2	264	871
Extensions and Discoveries	63	12	4	2	3	1	–	26	111
Acquisitions	–	–	–	20	4	–	–	–	24
Dispositions	–	(28)	(1)	–	(1)	–	–	–	(30)
Production	(43)	(17)	(10)	(10)	(9)	(4)	–	(5)	(98)
Revisions [3]	(11)	(42)	(18)	(2)	(1)	4	3	–	(67)
December 31, 2003	192	114	78	75	51	11	5	285	811
Probable Reserves									
December 31, 2002	98	50	12	14	15	12	15	117	333
Extensions and Discoveries	20	–	1	–	1	60	313	(26)	369
Acquisitions	–	–	–	8	2	–	–	–	10
Dispositions	–	(5)	–	–	–	–	–	–	(5)
Revisions	(23)	(7)	1	(1)	(6)	(8)	–	(6)	(50)
December 31, 2003	95	38	14	21	12	64	328	85	657
Proved + Probable Reserves									
December 31, 2002	281	239	115	79	70	22	17	381	1,204
Extensions and Discoveries	83	12	5	2	4	61	313	–	480
Acquisitions	–	–	–	28	6	–	–	–	34
Dispositions	–	(33)	(1)	–	(1)	–	–	–	(35)
Production	(43)	(17)	(10)	(10)	(9)	(4)	–	(5)	(98)
Revisions	(34)	(49)	(17)	(3)	(7)	(4)	3	(6)	(117)
December 31, 2003	287	152	92	96	63	75	333	370	1,468

Notes:

1 Reserves represent our working interest before royalties at year-end constant pricing. Since reserves were stated using forecast prices in prior years, the December 31, 2002 balances have been restated to reflect year-end pricing. Gas is converted to equivalent oil at a 6:1 ratio.

2 Probable reserves are determined according to SPE/WPC definitions.

3 Reserve revision breakdown:

mmboe	Reduction in Proved Undeveloped Reserves [4]	Change in Future Production Profile	Change in Economic Assumptions [5]	Total
Canada	(17)	(30)	(13)	(60)
Yemen	(11)	–	–	(11)
Other	–	4	–	4
Total	(28)	(26)	(13)	(67)

4 Based on drilling results and new geological mapping.

5 Relates primarily to changes in year-end Canadian dollar prices and future operating costs.

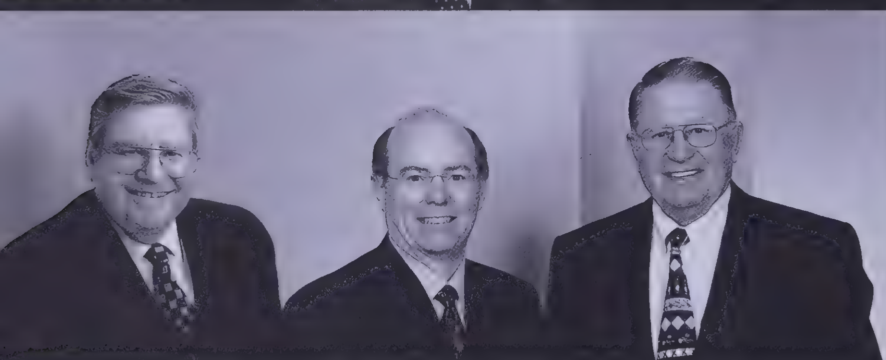
Directors

left to right

Victor J. Zaleschuk Retired President and Chief Executive Officer of Nexen Inc.

Francis M. Saville Q.C., retired Vice Chairman and Senior Partner of Fraser Milner Casgrain LLP, Barristers and Solicitors

Charles W. Fischer President and Chief Executive Officer of Nexen Inc.



Eric P. Newell Retired Chairman and Chief Executive Officer of Syncrude Canada Ltd.

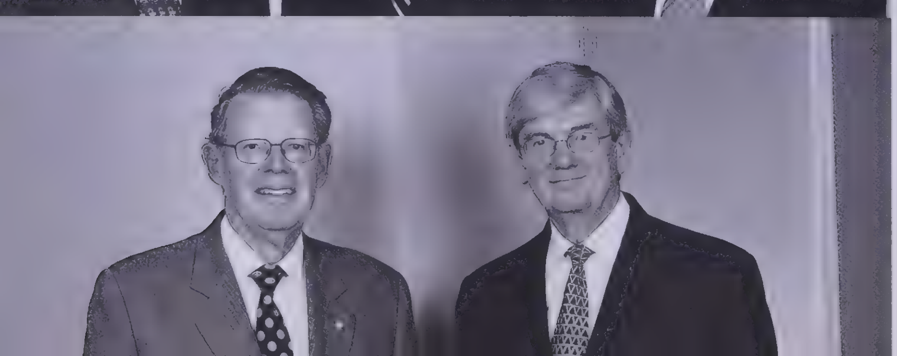
S. Barry Jackson Director and Executive Chairman of Resolute Energy Inc.

Dennis G. Flanagan Retired oil executive and a Director of NAL Royalty Trust

David A. Hentschel Retired Chairman and Chief Executive Officer of Occidental Oil and Gas Corporation

Kevin J. Jenkins Managing Director of TriWest Capital Management Corp.

Thomas C. O'Neill Retired Chairman of PwC Consulting



Richard M. Thomson Retired banking executive and a Director of the Toronto-Dominion Bank

John M. Willson Retired President and Chief Executive Officer of Placer Dome Inc.

Gordon R. Wittman, Retired President and Chief Operating Officer and a Director of Dupont Canada Inc., retired from Nexen's Board of Directors on May 6, 2003.

Officers

left to right

Charles W. Fischer President and Chief Executive Officer

Nancy F. Foster Vice President, Human Resources and Corporate Services

Richard M. Thomson Chairman of the Board

Marvin F. Romanow Executive Vice President and Chief Financial Officer

Gary H. Nieuwenburg Vice President, Synthetic Crude

Thomas A. Sugalski Senior Vice President, Chemicals

Douglas B. Otten Senior Vice President, United States Oil and Gas

Roger D. Thomas Senior Vice President, Canadian Oil and Gas

Laurence Murphy Senior Vice President, International Oil & Gas

John B. McWilliams Q.C., Senior Vice President, General Counsel and Secretary

Sylvia L. Groves Assistant Secretary

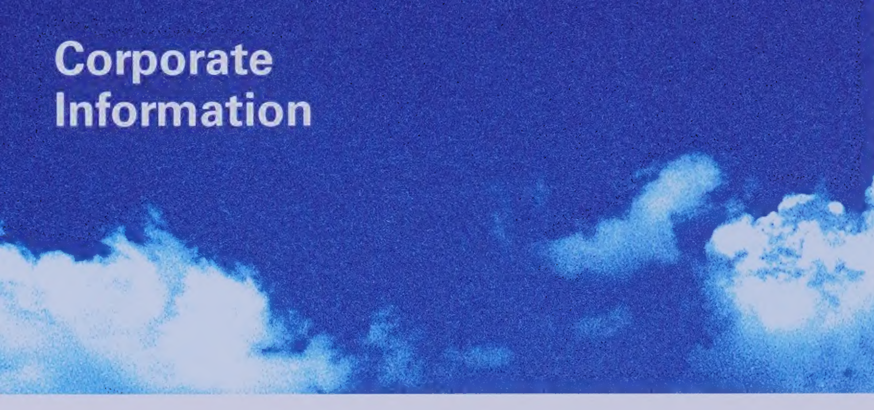
Rick C. Beingessner Assistant Secretary

Kevin J. Reinhart Vice President, Corporate Planning and Business Development

Una M. Power Treasurer

Michael J. Harris Controller

For more information on our Directors and Officers, please see Item 10 on page 106 in our 10-K.



Corporate Information

CORPORATE GOVERNANCE

Nexen's Board of Directors takes their duties and responsibilities for good corporate governance seriously. Nexen supports and conducts business according to the rules and guidelines of the Toronto and New York stock exchanges. We currently report our governance practices in compliance with the adopted and proposed TSX guidelines and the NYSE rules in our Proxy Statement and Information Circular.

Our CEO has certified to the NYSE that he is unaware of any violation by Nexen of the NYSE's corporate governance listing standards. As well, our CEO and CFO have certified the quality of Nexen's public disclosure to the Securities and Exchange Commission.

OPERATING ENTITIES

Chemicals

Nexen Chemicals Canada Limited Partnership
Nexen Chemicals U.S.A.
Nexen Química Brasil Ltda.

Marketing

Nexen Marketing
Nexen Marketing U.S.A. Inc.
Nexen Marketing International Ltd.
Nexen Marketing Singapore Pte Ltd.

Canada

Nexen Petroleum Canada

United States

Nexen Petroleum U.S.A. Inc.
Nexen Petroleum Offshore U.S.A. Inc.

International

Canadian Nexen Petroleum Yemen
Canadian Nexen Yemen Ltd.
Nexen Petroleum Australia Pty Limited
Nexen Petroleum Colombia Limited
Nexen Petroleum do Brasil Ltda.
Nexen Petroleum Equatorial Guinea Limited
Nexen E & P Services Nigeria Limited
Nexen Petroleum Nigeria Limited

FORWARD-LOOKING INFORMATION

Certain statements in this report are "forward-looking statements" within the meaning of the United States *Securities, Private Litigation Reform Act of 1995,* Section 21E of the United States *Securities Exchange Act of 1934,* as amended, and Section 27A of the United States *Securities Act of 1933,* as amended. Forward-looking statements are generally identifiable by terms such as "intend", "plan", "expect", "estimate", "budget" or other similar words. The forward-looking statements are subject to known and unknown risks and uncertainties, and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied. Please read item 7 and the note regarding forward-looking statements in our Form 10-K on page 59 for a full discussion of the risks and uncertainties associated with our business.

CAUTIONARY NOTE TO U.S. INVESTORS

The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to discuss only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this annual report, excluding the Form 10-K, we refer to "recoverable resource" and "probable reserves" which are inherently more uncertain than proved reserves. In our Form 10-K filed with the SEC, we refer only to "proved reserves."

SPECIAL NOTE TO CANADIAN INVESTORS

Nexen is an SEC registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures generally follow SEC requirements. We have received an exemption from Canadian securities regulatory authorities to continue disclosing our oil and gas activities and reserves using SEC requirements instead of Canadian disclosure requirements under *National Instrument 51-101* (NI 51-101) — *The Standards of Disclosure for Oil and Gas Activities.* SEC reserves disclosure differs from the corresponding information if it were prepared using NI 51-101. Please see page 60 of our Form 10-K for a discussion of the exemptions obtained and resulting differences. Our probable reserves disclosure applies the Society of Petroleum Engineers/World Petroleum Council (SPE/WPC) definition for probable reserves. The Canadian Oil and Gas Evaluation Handbook states there should not be a significant difference in estimated probable reserve quantities using the SPE/WPC definition versus NI 51-101.

Corporate Information

HEAD OFFICE

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Calgary, Alberta, Canada T2P 3P7
403.699.4000
www.nexeninc.com

COMMON SHARE TRANSFER AGENT AND REGISTRARS

CIBC Mellon Trust Company
Calgary, Toronto, Montreal, Regina, Winnipeg, Vancouver and Halifax

ChaseMellon Shareholder Services
New York, NY

STOCK SYMBOL: NXY

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

SUBORDINATED NOTES

7.35% due 2043
NYSE: NXYPRB
TSX: NXY.PR.B

DIVIDEND REINVESTMENT PLAN

Nexen's Dividend Reinvestment Plan allows shareholders to purchase additional common shares by reinvesting the cash dividends they receive without paying any brokerage fees or service charges.

A copy of the offering circular (and for United States residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or on the internet at www.cibcmellon.ca.

AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

DUPLICATE REPORTS

Although we strive to ensure our registered shareholders receive only one copy of this annual report, duplication is unavoidable if securities are registered in multiple accounts under different names and addresses. If you received more than one copy of this report, please call CIBC Mellon at 1.800.387.0825.

SUSTAINABILITY REPORT

Nexen produces a Sustainability Report that outlines our safety, environment and social responsibility performance. Our 2003 Sustainability Report will be available this fall. For more information, e-mail integrity@nexeninc.com or call Pam Hicks at 403.699.5297.

WEBSITE

Nexen's statistical supplement and other financial documents are available online at www.nexeninc.com. Hard copies may be ordered through the Investor Centre on our website or by calling 403.699.5931.

ANNUAL GENERAL MEETING

The Annual General and Special Meeting of Shareholders will be held on Tuesday, May 4, 2004, at 11:00 a.m. Mountain Time, in the Crystal Ballroom at the Fairmont Palliser Hotel in Calgary, Alberta, Canada.

INVESTOR RELATIONS CONTACT

Grant Dreger
Telephone 403.699.5273
Fax 403.699.5730
grant_dreger@nexeninc.com

FEEDBACK

We welcome your feedback on this report. Please email annual_report@nexeninc.com or phone 403.699.4791.

ABBREVIATIONS

bbl	barrel
bbls/d	barrels of oil per day
bcf	billion cubic feet
boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
F&D	finding and development
G&A	general and administrative
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
WTI	West Texas Intermediate

CONVERSIONS

Natural gas is converted at 6 mcf per equivalent barrel of oil.

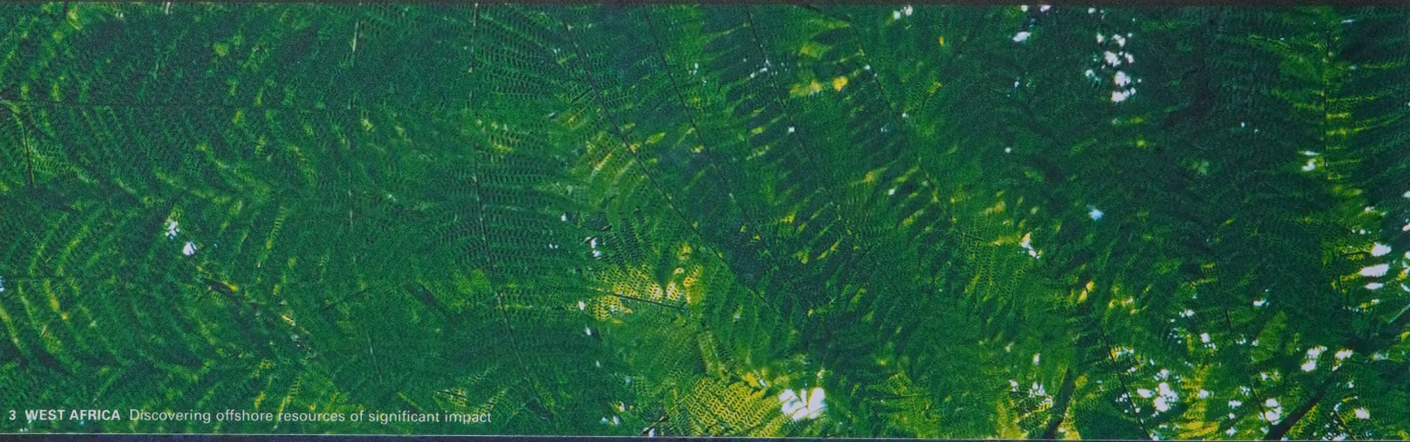
DOLLAR AMOUNTS

In Canadian dollars unless otherwise stated.

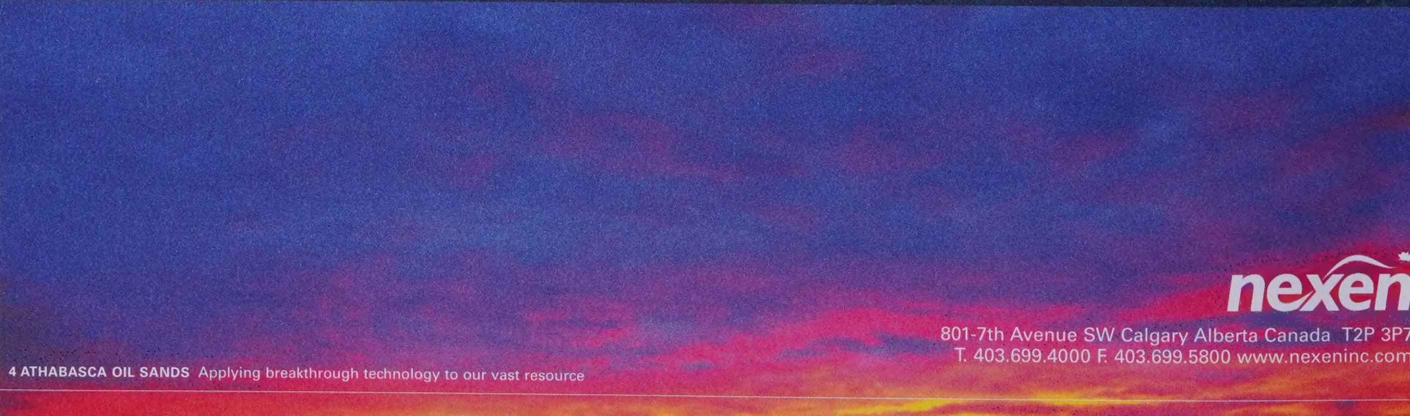
Created by Perspectives MGM Inc.,
Letterbox Design Group and DaSilva Graphics
Printed in Canada by Blanchette Press.

1 **GULF OF MEXICO** Investing in higher-margin barrels in the deep water

2 **MIDDLE EAST** Growing new reserves and cash flow in low-cost areas



3 **WEST AFRICA** Discovering offshore resources of significant impact



4 **ATHABASCA OIL SANDS** Applying breakthrough technology to our vast resource